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The Liberalisation of the Power Industry in the European Union and its Impact on Climate Change

A Legal Analysis of the Internal Market in Electricity

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ABSTRACT
The liberalisation of the European power industry has fundamentally modified the regulatory framework of electricity utilities. This paper discusses why the European Union (EU) has introduced competition into the power sector and examines how the principal reforms adopted at the EU level shape its current and long-term emissions of carbon dioxide. To appreciate the impact of liberalisation on climate change, the paper follows a two-step process. The first step is to provide an overview of the European fuel mix, the main power generation technologies and their carbon intensity. The second step is to analyse the new legal framework and the changes resulting from liberalisation in terms of demand patterns, research, development and operation of networks and power generation. Particular attention is paid to the risks faced by investors in new power generation. The study concludes that if a lock-in of the European power industry in highly CO_2-intensive fossil fuels is to be avoided a significant overhaul of the current legal framework is necessary. Such a reform would have to place a special focus on the incentives provided by network regulation and re-appraise the institutional design as only a profound modernisation of the grids, supported by strong institutions will allow the large-scale uptake of renewable energy sources.

KEY WORDS
THE EUROPEAN UNION, EUROPEAN POWER INDUSTRY, CLIMATE CHANGE, LIBERALIZATION

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Arctic ice is melting at an unprecedented rate, glaciers are visibly shrinking and fires characterised by extreme heat and droughts are devastating Mediterranean forests more than ever. We can sense it, the climate is changing – or are these phenomena just a reflection of the normal variations of weather patterns? The response of the Intergovernmental Panel on Climate Change (IPCC)[1] in its 4th Synthesis Report on climate change, released on 17 November 2007, is unequivocal.[2] The global average temperature has increased over the last 100 years by 0.76 degrees Celsius (°C) and 'eleven of the last twelve years (1995-2006) rank among the twelve warmest years in the instrumental record of global surface temperature'. The IPCC also provides the explanation for this change: the unprecedented release of anthropogenic greenhouse gas emissions is the 'very likely'[3] cause of the increase in the global average temperature with its irreversible and possibly catastrophic consequences for the Earth.[4]

Global emissions of greenhouse gases due to human activities have grown steadily since pre-industrial times, with an increase of 70% between 1970 and 2004.[5] This growth is strongly correlated with the rise in energy-related greenhouse gases,[6] emitted mainly by combustion of fossil fuels, which account for approximately 70% of total emissions.[7] And this trend will not stop unless decisive policies are adopted.[8] The IPCC Special Report on Emission Scenarios[9] projects an increase in global emissions of greenhouse gases of 25–90% between 2000 and 2030. Depending on the emission scenario,[10] a further increase in global temperature of between 1.1 and 6.4 °C in the 21st century cannot be excluded.[11]

Confronted with this unprecedented threat, in 1992 192 nations signed the United Nations Framework Convention on Climate Change (UNFCCC) aiming at the stabilisation of

[1] The Intergovernmental Panel on Climate Change (IPCC) was established in 1988 under the auspices of the United Nations Environment Programme and the World Meteorological Organization for the purpose of assessing 'the scientific, technical and socioeconomic information relevant for the understanding of the risk of human-induced climate change'. To date, the IPCC has issued four comprehensive assessments; in 1990, 1996, 2001 and 2007. More than 2500 scientists contributed to these assessments, relying mainly on published and peer-reviewed scientific technical literature. The IPCC shared the 2007 Nobel Peace Prize with former Vice President of the United States Al Gore. See http://www.ipcc.ch.
[2] See IPCC (2007a: 2).
[3] According to the IPCC 'very likely' means that there is more than a 90% chance. See IPCC (2007a: 1).
[4] The IPCC summarises the regional and global consequences which are likely if the global temperature exceeds certain temperature thresholds. See IPCC (2007a); Schellnhuber et al. (2006).
[5] Emissions of carbon dioxide, the most important anthropogenic greenhouse gas, have risen by 80% during this time. See IPCC (2007a: 4).
[6] At the sector level, the largest contributors to global emissions are electricity and heat (collectively 24.6%), land-use change and forestry (18.2%), transport (13.5%), and agriculture (13.5%). Oil constitutes the most commonly used energy fuel at 35% of global primary energy use, followed by coal (24%) and natural gas (21%). If current trends prevail, the world will use 60% more energy in 2030 than in 2002. See Baumert et al. (2005: 41); Lamy (2006: 1); IEA (2004: 58).
[7] These emissions are mainly carbon dioxide but also include methane and some traces of nitrous oxide. See IPCC (2007b: 253).
[8] Notwithstanding actual mitigation efforts, emissions of CO_2 have increased globally by 3% per annum since 2000. See *Le Monde*, 22 March 2008, p. 7.
[9] IPCC (2000).
[10] The IPCC set up 6 different emission scenarios. See IPCC (2007a: 7).
[11] See IPCC (2007a: 7).

'greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system'. The UNFCCC, however, never actually defined what it meant by 'dangerous'.[12] As a first step towards curbing global emissions, industrialised countries committed themselves in Kyoto to reducing their greenhouse gas emissions by a collective average of 5% below their 1990 levels within the period between 2008 and 2012.[13] The European Union (EU) fixed as its long-term climate target the limitation of the global mean temperature increase to 2 °C above pre-industrial levels.[14] To have a chance to reach this target, CO_2 emissions must be reduced by 50 to 85% compared to 1990 levels by 2050, with a peaking year for CO_2 emissions between 2000 and 2015.[15] The European Council[16] pledged that the EU would reduce its greenhouse gas emissions by 20% by 2020 compared to 1990 levels and would endorse a 30% reduction objective provided that other developed countries commit themselves to comparable emission reductions and economically more advanced developing countries make an adequate contribution within the framework of the negotiation process launched at the Conference in Bali in December 2007.[17]

The long-term mitigation of climate change represents a daunting task for humanity, requiring simultaneously a rapid decarbonisation of our economies and a shift towards less energy-voracious lifestyles.[18] The electricity sector will have to make a significant contribution if the world is to have a reasonable chance of keeping climate change within acceptable limits. Indeed, electricity[19] generation is the main source of CO_2 emissions worldwide.[20] Having increased its emissions by 170% since 1971, the sector is responsible for about 40% of global CO_2 emissions.[21] In 2005, hard coal and lignite fuels accounted for about 40% of world electricity production, natural gas provided 20%, nuclear 16%, hydro 16%, oil 7% and other renewable energy sources about 2%.[22]

[12] See with regard to the impacts of global climate change at different annual mean global temperature increases Warren (2006); Meinshausen (2006); Schneider et al. (2006); Yamin et al. (2006).
[13] The Kyoto Protocol of the UNFCC was signed by more than 170 countries in 1997. The EU-15 committed to reducing their greenhouse gas emissions by an average of 8%. As of December 2007, the US and Kazakhstan were the only signatory nations not to have ratified the act.
[14] See European Commission, COM (2007) 2. According to numerous scientific studies an increase of 2 °C above pre-industrial levels will cause severe damage to the world's coral reefs and the disappearance of many glaciers throughout the world. Most alarming, the climate system might pass a critical tipping point that will inevitably and irreversibly lead to a massive loss of the Greenland ice sheet and a rise in sea levels of up to 20 feet. See http://www.fightglobalwarming.com.
[15] This reduction target is estimated for a likely temperature increase of between 2 and 2.4 degrees, based on the best estimate for climate sensitivity. See IPCC (2007a: 15).
[16] European Council, 8/9 March, 2007, 7224/1/07 REV 1.
[17] The Bali Conference brought together representatives of over 180 countries and culminated in the adoption of the Bali Roadmap, which charts inter alia the course for a new negotiating process designed to tackle climate change, with the aim of completing this by 2009.
[18] See for an overview of mitigation scenarios den Elzen et al. (2006).
[19] Electricity is a high-value energy carrier, which is effective as a source of motive power, lighting, heating and cooling and the prerequisite for electronics and computer systems. See IPCC (2007b: 282).
[20] IEA (2006: 170).
[21] More than 40% of all electricity is consumed in buildings, either residential (23%) or commercial and public. Industry accounts for a further 35% of electricity use. About 9% is consumed in energy production and processing (for example refineries) and an equal amount is lost in transmission and distribution. See Baumert et al. (2005: 59).
[22] IPCC (2007b: 260).

Emissions of CO_2 from electricity generation stem essentially from fossil fuels. While power stations fuelled by nuclear energy and most renewable energy sources emit virtually no CO_2 during their operational life, coal-fired electricity plants accounted for some 70%, natural gas-fired plants for about 20% and oil-fired plants for about 10% of the sector's global CO_2 emissions in 2003.[23] If current trends continue, electricity demand will double between 2002 and 2030, increasing the contribution of power generation to global energy-related CO_2 emissions to about 44%.[24] Although developing countries will drive this increase by tripling their consumption and their emissions in this period, 1.4 billion people will still lack any access to an electricity supply in 2030.[25]

When analysing the options of the electricity industry for significantly reducing its CO_2 emissions, the International Energy Agency (IEA) underlined the necessity to have recourse to all available technological solutions.[26] These include making the switch to carbon-free and lower carbon generation technologies as well as highly efficient end-use technologies and the use of carbon capture and storage (CCS).[27] The IEA highlighted that the existing electricity plants in OECD[28] countries were aging and would have to be replaced in the next 10 to 20 years.[29] This fact, combined with the rapidly growing demand for electricity in developing countries, implies that investment decisions in the next few years will have a long-term impact, locking the electricity system into a fuel mix and emissions trajectory that will be difficult to change.

Before discussing the various instruments which might contribute to a decarbonisation of the electricity industry, it is important to understand the influence of the recent worldwide wave of liberalisation on emission trends. In this paper we shall focus mostly on the liberalisation process launched by the EU. Even though it describes essentially the changes that occurred in Europe and how they affected demand patterns, operation and investment conditions of power generation, the conclusions may well apply *mutatis mutandis* to other countries with liberalised power industries.

This paper is divided into two sections. In the first section we examine the reasons for the liberalisation of the electricity industry and present the main reforms adopted in the EU. In the second section we give a short overview of the main power generation technologies and their carbon intensity, followed by a description of the main changes

[23] IEA (2006: 171).

[24] The global average growth rate since 1995 has been 2.8%. According to the International Energy Agency (IEA) this trend will continue under a business-as-usual scenario. According to the so-called baseline scenario electricity demand is expected to increase at an average annual rate of 2.5%.. See IEA (2004: 192).

[25] Coal- and gas-fired generation will provide more than three-quarters of the world's increased demand for electricity until 2030. The largest increase will be in residential electricity consumption followed by the service sector and industry. See IEA (2004: 196, 211).

[26] At the request of the G8, the IEA developed a range of scenarios and strategies to reduce CO_2 emissions until 2050. They distinguished several scenarios. See IEA (2006). For Europe see the scenarios of the EEA (2005b).

[27] The CCS technology allows the separation of CO_2 from fossil fuels and its storage underground. See IEA (2007:1).

[28] OECD stands for the Organisation for Economic Co-operation and Development.

[29] IEA (2006: 171).

entailed by the European liberalisation process and its impact on trends in emissions by the power industry.

In assessing the impact of the European liberalisation process on climate change we don't analyse in detail the effects of the instruments adopted by the EU to address climate change, in particular the Directive on the promotion of electricity produced from renewable energy sources[30] or the European-wide scheme for trading in greenhouse gas emission allowances[31] (the 'ETS'), as this would exceed the scope of this study. An analysis of the measures aiming exclusively at the creation of a competitive electricity market is, however, not possible and probably not desirable as liberalisation and climate policies are increasingly intertwined. But by placing the focus on the measures adopted to introduce competition into the industry, this study allows us to demonstrate more clearly how the liberalisation process has contributed to shaping current and future emission trends, while progressively integrating certain concerns related to climate change.

I. The liberalisation of the power industry

A. *The case for liberalisation*

The invention of a generator producing alternating current, which allows electricity to be sent thousands of kilometres without losing too much energy, is at the root of the present structure of the power industry – a system which generates electricity in large power stations at remote sites and carries it over long distances to reach its final users.[32] This model, also called the 'central-station' system because everything is connected to the same network of wires and operated in the same synchronised rhythm, is currently the worldwide standard.[33]

To keep it stable the entire system has to be operated centrally. The simplest way to manage it is for the entire system to be operated by a single management body, a vertically integrated company responsible for the whole value chain: *generation* which converts energy sources into electricity, *transmission* which occurs when electricity is transmitted over high voltage networks to major demand centres; *distribution* which is the process by which transmitted power flows to final consumers such as factories and

[30] Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market, O.J. 2001 L 283, p. 33–40 (hereafter the 'RES-Directive'). When implementing the RES-Directive several Member States decided to adopt so-called 'feed-in tariffs' to support electricity generated from renewable energy sources. A feed-in tariff is an incentive structure that boosts the deployment of renewables through the obligation placed by governments on electricity utilities to buy electricity generated from renewable sources above market rates. See in particular on this subject the doctoral thesis of Sawin (2004).

[31] Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for trading in greenhouse gas emission allowances within the Community and amending Council Directive 96/61/EC, O.J. 2003 L 176/37.

[32] Before this discovery, facilities relied exclusively on direct current, which meant that generators had to be reasonably close to the appliances functioning with electricity because large power losses were incurred during the transport of electricity. See Patterson (1999: 42).

[33] See Patterson (1999: 22).

homes; and *supply* – the name given to the metering, billing and bundling of contracts with the other business by which consumers arrange to pay for their supplies of electricity.[34]

Until the late 1970s, electricity systems almost invariably consisted of vertically integrated companies with an exclusive right to sell electricity and a corresponding obligation to supply it. As the services they provided were seen to be of strategic importance for the overall economy, state owned firms controlled the industry in most OECD countries.[35] Where private ownership was substantial, governments subjected electric utilities to wide-ranging regulatory and financial legislation.[36]

The setting up of monopolistic central stations, whether owned or only regulated by public authorities, resulted in an industry characterised by large scale investment and a lack of competition, and organisations often dominated by considerable engineering excellence but little commitment to cost minimisation.[37] A serious shortcoming of the system was that those who planned, managed, and operated the system did not carry any of the risk and did not suffer if they erred.[38] They invested vast sums in projects that seriously exceeded budgets, fell years behind schedule and did not meet design specifications.[39] Consumers had almost no role other than to switch things on and off.

The system of vertically integrated electricity utilities was hence increasingly criticised.[40] Utilities operating under monopoly conditions were accused of encouraging managerial slack, giving insufficient attention to research and development, engaging in rent-seeking behaviour and squashing innovations by rivals that would reduce their profits.[41] Moreover, they were accused of showing insufficient concern for customer service, reacting slowly to new market developments and of being incapable of attracting expertise or leveraging the talents of skilled people.[42] Another criticism was that the regulators of these industries often lost track of public interest and most notably served the interests of those they regulated.[43]

[34] Pollitt (1997: 1).
[35] Cameron (2002: 1.10).
[36] Pollitt (1997: 2).
[37] Patterson (1999: 86).
[38] For an overview of five sets of theories describing how liberalisation is likely to improve economic efficiency see Pollitt (1997: 5).
[39] Patterson (1999: 86).
[40] Isidoro reports that Hicks had already written in 1932: “The best of all monopoly profits is a quiet life”. See Isidoro (2006: 93).
[41] Stiglitz et al. (2002: 269). For a good summary concerning the main economic criticisms levelled against electricity monopolies see Isidoro (2006: 91 ff.).
[42] Stiglitz et al. (2002: 273).
[43] This can happen through bribery and corruption, but the much likelier way is that over time, employees of a regulated industry develop personal friendships with the regulators, who in turn come to rely on their expertise and judgement. By the same token, regulators who demonstrate an ‘understanding’ of the industry are rewarded with good jobs in that industry after they leave government service. See Stiglitz et al. (2002: 275).

This situation was judged unanimously as detrimental to the healthy management of the utility.[44] From the mid-1980s onwards, a process referred to as 'globalization'[45] further challenged the close ties between the governments and the electricity industry.[46] Energy-intensive firms, which had to keep up increasingly with worldwide competition,[47] put pressure on governments to find ways to reduce energy prices.[48]

Finally, the development of small-scale technologies further exacerbated the climate of increasing doubt about the necessity of maintaining the prevailing monopolistic structure.[49] By giving 'independent' generators the chance to sell electricity to the monopoly system, the United Kingdom and the United States showed that alternatives to vertically integrated electricity systems could operate without causing a decline in the quality of service provided through the system.[50]

A new political rhetoric, the so-called 'neo-liberalism', whose advocates believed in the superiority of market forces and asked for government to step back from the economic sphere, gained ground.[51] Supported by the increased use of information technology, the introduction of competition in electricity markets was deemed possible and desirable. Under the influence of neo-liberalist ideas a number of governments committed to 'free markets' began to reappraise the monopoly of electricity providers.[52]

In 1982 Chile was the first country in the world to undertake a comprehensive reform of its electricity sector.[53] The United Kingdom imitated this example in 1989 by privatising the electricity industry and introducing a competitive market into electricity generation and supply. It was followed by Norway in 1991, which opened its generation and supply markets to competition. Other countries chose a similar route, among them Argentina, Mexico, some states of North America (Ontario, Quebec and California), Australia and New Zealand.[54]

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[44] Isidoro (2006: 97).
[45] The globalisation process was, in particular, promoted by the General Agreement on Tariffs and Trade (GATT) which spells out principles of liberalisation and includes commitments by individual countries to lower customs tariffs and other trade barriers.
[46] Cameron (2002: 1.17).
[47] Energy prices in the European Union were high in comparison with those of their competitors. According to a report of the European Commission, in the 1990s the chemical sector in the European Union paid up to 45% more than their US competitors. See COM (97) 167.
[48] Nations increasingly had to abide by rules of non-discrimination. See Cameron (2002: 1.18).
[49] See also Isidoro (2006: 91 ff.).
[50] Cameron (2002: 1.16).
[51] Isidoro states that no explicit 'neo-liberal' theory exists, but only different currents, promoted in particular by authors such as Friedman, Buchanan, Tollison, Lucas and Sargent. They all share a lack of confidence in state intervention and judge the latter to be useless in most cases if not detrimental to the economy. According to Isidoro, 'neo-liberalism', which was largely politicised but hardly theorised, represents a rhetoric rather than an ideology and represents a critical response in the face of the obvious failures of former public policies. See Isidoro (2006: 120).
[52] Patterson (1999: 87).
[53] Pollitt (2004).
[54] Cameron (2002: 1.08).

B. The liberalisation of the power industry in the EU

1. Electricity and European Community Law

Until the end of the 1980s European Community law hardly intervened in the organisation of national electricity utilities. This abstinence may at first seem paradoxical.[55] Energy was indeed a key component in the post-war reconstruction and two of the three founding treaties of the European Communities were specifically directed at regulating energy.[56] Electricity, however, was not dealt with explicitly by any of the three Treaties, nor were gas or oil.[57] For a long time, it remained uncertain whether the provisions of the Treaty should apply to electricity.[58] In 1964, in the 'Costa' case,[1] the European Court of Justice answered this question indirectly by accepting that electricity may fall within the scope of Article 31 EC Treaty[59]. But it was only in the 'Almelo'[60] case in 1994 that the European Court of Justice explicitly recognised that the rules on the free circulation of goods of the EC Treaty also applied to electricity.

Despite the judgment in the 'Costa' case, the 'quiet life' of the national electricity monopolies remained basically unchallenged by Community law for quite some time. After the 'oil shock' of 1974 some restrictions were imposed on electricity utilities with respect to the use of gas for electricity, but no other steps were taken to change the structure of the industry.[61] Although energy was high on the agenda in the second half of

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[55] The Foreign Ministers of the ECSC Member States had, indeed, explicitly called for urgent action in the energy sector at the Conference of Messina in 1955. Moreover, the 'Spaak Committee', which laid down the foundations for the EURATOM and the EEC Treaties, had established an expert Commission that devoted a whole section of its report to energy. See Daintith et al. (1986: 17).

[56] The Treaty of Paris, signed in 1951, founded a supranational coal regime through the establishment of the European Coal and Steel Community (ECSC Treaty) and the EURATOM Treaty created the European Atomic Energy Community. The European Economic Community Treaty (EEC Treaty), which became the European Community Treaty (EC Treaty) in 1993, which came into effect in conjunction with the EURATOM on 1 January 1958, in contrast, contained no specific provisions on energy, but provided for the establishment of a common market of goods, persons and services, a customs union and common policies. It should be recalled here that coal represented two thirds of the energy supply of the Member States of the ECSC in the 1950s. See Roggenkamp et al. (eds.) (2001: 214).

[57] The Spaak Report at the origin of the EEC Treaty (the 'Treaty') had, indeed, considered that market rules should not immediately apply to energy sources other than coal and nuclear. See the Report of the Heads of Delegation to the Ministers of Foreign Affairs (21 April 1956), commonly known as the Spaak Report, which prepared the establishment of the Treaty of Rome, p. 126–129, at: http://aei.pitt.edu/996/01/Spaak_report_french.pdf; Börner (2005:181); Daintith et al. (1986:15).

[58] See ECJ, Case 6/64 Costa v ENEL [1964] ECR 1141; Isidoro (2006: 142).

[59] Article 31 EC Treaty (formerly Art. 37 EEC) states that Member States shall adjust any State monopolies of a commercial character so as to ensure that no discrimination regarding the conditions under which goods are procured and marketed exists between nationals of Member States.

[60] It stated: 'In Community law, and indeed in the national laws of the Member States, it is accepted that electricity constitutes a good within the meaning of Article 30 of the Treaty'. See ECJ, Case C-393/92 Almelo and Others [1994] ECR I-1477, par. 28.

[61] Council Directive on restriction of use of natural gas in power stations, O.J. 1975, L178/24; Council Directive 75/405 on the restriction of the use of petroleum products in power stations, O.J. 1975, L 178/26.

the 1970s, Member States were reluctant to abandon their sovereignty and the Community remained unsuccessful in devising an ambitious energy policy.[62]

A more radical change of strategy was announced by the well-known White Paper on the completion of the internal market[63] and the entry into force of the Single European Act (SEA). Although the SEA did not provide a title on energy policy,[64] it was to prove a turning point. In a report published in 1988[65] the European Commission stated unambiguously that it was determined to enforce the general provisions of the EEC Treaty in the energy sector. In the follow-up, two directives in the field of transparency of electricity prices[66] and international electricity transit[67] were adopted within an interval of four months in 1990. Both directives remained, however, modest in scope and influenced the organisation of the national electricity systems only marginally.[68] In 1991 the Commission went a step further. It set up two expert groups whose task was to study whether competition could be introduced by giving non-vertically integrated, so-called 'independent' electricity producers access to the grids.

Despite the opposition expressed by the main stakeholders and many Member States, in February 1992 the Commission presented a Directive proposal[69] based on the principle of 'regulated' third-party access ('TPA'),[70] which implies that third parties, often competitors of the generation, supply and distribution divisions of the transmission facility owner, are legally entitled to use such facilities against a reasonable fee and on practical technical terms.[71] The two other main 'agents of change' of the proposals were the abolition of exclusive rights in the production and supply sectors by a licensing system[72] and the 'unbundling' or administrative separation of the functions of production, transmission, distribution and supply.[73]

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[62] Its main action consisted in setting up a strategy in which Member States were requested to use energy more efficiently, to mitigate oil dependency by increasing coal consumption, to pursue vigorous nuclear programmes and to develop renewable energy sources. See European Commission, COM (81) 540 final; Cameron (2002: 2.24); Council, Recommendation 81/924/EEC on electricity tariff structures in the Community, O.J. 1981 L 337 , p. 12–13; Isidoro (2006: 189).

[63] The White paper sets out the tasks that the Commission saw as being necessary for the completion of the internal market. See European Commission, COM (85), 310.

[64] The new title for environment explicitly acknowledged that measures significantly affecting a Member State's choice between different energy sources and the general structure of its energy supply could only be taken by unanimous decision. See Article 130 s (2) EC Treaty (actual Article 175 (2) EC Treaty); Cameron (2002: 2.34).

[65] See European Commission, COM (88) 238.

[66] Council Directive 90/377 concerning a Community procedure to improve the transparency of gas and electricity prices charged to industrial end-users, L 1990 185/16. See Marquis (2001: 29); Isidoro (2006: 173).

[67] Council Directive 90/547 on the transit of electricity through transmission grids O.J. 1990 L 313/33.

[68] For a more thorough analysis of the transit directive see Isidoro (2006: 178); Andersen (1997: 7); Cameron (2002: 3.49).

[69] European Commission, Proposal for a Council Directive concerning common rules for the internal market in electricity, O.J. 1990 C65/94.

[70] See for more details on this process Isidoro (2006: 199).

[71] Wälde (2002: 197).

[72] The Commission proposed to introduce a licensing system, which meant that the generation of electricity would be allowed on the basis of transparent and non-discriminatory criteria. According to the

The Commission proposal was met with great scepticism.[74] It took four years of negotiations before the first Directive establishing common rules for the internal market in electricity could finally be adopted in December 1996.[75] It represented the first important step in the creation of a Europe-wide competitive electricity market.[76] A year and a half later, a similar Directive opening up the gas markets was adopted.[77]

2. The first Electricity Directive

a) The legal framework

The first Electricity Directive set up a new framework of rules based on competition in generation and the freedom of consumers to choose their electricity provider.[78] The 'natural monopoly status' of the transmission and distribution segments was, however, maintained. Unlike the telecommunication sector, the Directive did not open the markets at once, but set a timetable, which granted a gradual and minimal opening of the market by up to 33% over a period of six years.[79] Thus, it was mainly large consumers, the so-called 'eligible' customers, who were to become the beneficiaries of the new possibilities, while the majority of consumers remained captive.[80]

To ensure network access for producers and consumers, Member States had to adopt either a TPA system or opt for the 'Single Buyer System'.[81] If a Member State opted for a TPA system, it could choose between two variants, namely a 'negotiated'[82] and a 'regulated' TPA.[83]

Commission, this would increase the potential for investment by independent operators while permitting national authorities to reject proposals for new investments.

[73] Cameron (2002: 3.66).

[74] While Member States voiced concern about security of supply aspects, protection of small consumers and investment issues, the newly created professional association Eurelectric strongly opposed the principle of TPA. See Cameron (2002: 3.74).

[75] Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity, O.J. L 27/20; 31.1.1997. In the text that follows reference will be made to this Directive either just by the term 'first Electricity Directive' or first E-Directive'. The Directive was based on Article 95 of the EC Treaty. See for an extensive discussion of the negotiation process Andersen (1997: 15); Jabko and Eising (2000); Marquis (2001: 72).

[76] Jones ed. (2004: 2.12).

[77] O.J. L204/1; 2.7.1998.

[78] For more details on the provisions of the first E-Directive see Marquis (2006: 76ff).

[79] See for more details on the opening Isidoro (2006 : 231). This limitation was the result of a compromise between the Nordic countries and Germany, which argued for a larger opening, and the countries of the South, which wanted their traditional operators to be protected from a brutal opening of the market.

[80] See Article 2 par. 7 and 8 first E-Directive.

[81] See Articles 16-17 first E-Directive.

[82] 'Negotiated' access meant that the network operator was obliged to negotiate a right of use of its network but could refuse access based on 'duly substantiated reasons'. Furthermore, Member States had to designate an independent body to resolve conflicts in connection with contract negotiation. See Article 17(5) first E-Directive.

[83] Under 'regulated' access, third parties who met the relevant technical standards were eligible for access to the network upon payment of a regulated tariff, provided capacity was available. The terms of access

Regarding generation, the Directive contemplated two alternative vehicles for the construction of new capacity: an 'authorisation' and a 'tendering' procedure.[84] Under the authorisation procedure the generation sector was fully opened to competition, subject only to standard licensing requirements.[85] The tendering procedure could be chosen as an alternative or in addition to the authorisation procedure.[86]

In order to limit the risk that vertically-integrated electricity suppliers would discriminate against competitors by granting preferential network access to their own supply business and less favourable access to their competitors, the Directive required a split of their accounts. This meant that these undertakings had to maintain separated accounts for generation, transmission and distribution by recording their costs and revenues on a differentiated basis.[87] It also allowed generators to build direct lines to supply their own premises, subsidiaries or customers.[88]

Member States had, moreover, to appoint a Transmission System Operator (TSO), who was responsible for operating, maintaining and, if necessary, developing the network and the 'interconnections' in a given geographical area.[89] The TSO was, in particular, accountable for the dispatch of electricity in its area, and for determining the use of capacity available through the 'interconnectors'[90]. Similar rules applied to Distribution Transmission Operators (DSOs) with respect to the distribution network.[91]

Finally, the Directive made allowance for the strong public service tradition in some Member States by allowing the imposition of certain public service obligations on electricity undertakings.[92] By the same token, it recognised that the realisation of legitimate objectives by the Member States made it necessary to allow Member States to derogate from the full application of certain provisions.[93]

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were left to national regulators. See Article 17 (4) first E-Directive. See for more details Marquis (2001: 86 ff.).

[84] See also Marquis (2001: 78).

[85] Article 5 first E-Directive.

[86] It meant that Member States had to conduct the call for tenders according to an inventory based on estimates of future demand. This system made it possible for Member States to control investment decisions rather then to leave them exclusively to the market. See Article 6 first E-Directive.

[87] See Articles 13-15 first E-Directive. See Marquis (2001: 83).

[88] Article 21 (3) first E-Directive made clear that the fact that a company constructs a direct line in no way prevents it from also having access to the main grid. Member States could, however, limit this right and make it subject to the fact that the company wishing to build the direct line had requested access to the main grid and that access had been refused on the grounds of a lack of capacity. See Jones (2004: 9.6).

[89] See Article 8 (1) first E-Directive.

[90] Interconnector means the equipment used to link electricity systems. See Article 2 (10) first E-Directive.

[91] Articles 10-12 first E-Directive.

[92] According to Article 3 (2) first E-Directive public service obligations may relate to security, including security of supply, regularity, quality and price of supplies and environmental protection. See for more details on this subject Marquis (2001: 101).

[93] See for instance Article 24 first E-Directive. Based on this provision the Commission granted the German VEAG a derogation to allow this operator to fulfil its commitment to maintain electricity generation from lignite or brown coal and to make large investments in the modernisation of generation

Although the Directive entered into force four years after the signature of the Rio Framework Convention, the potential negative impacts of the liberalisation process on the climate were largely ignored.[94] The Directive did contain, however, certain references to environmental protection and renewable energy sources.[95] Beside these clauses, which did not set any limit on the industry with respect to greenhouse gas emissions, the Directive contained no provisions to mitigate potential detrimental consequences for the climate.

b) The difficult emergence of a truly competitive internal electricity market

The first Electricity Directive had established a legal framework which laid down the basic structural reforms for liberalisation. It left, however, many requirements for achieving a truly competitive market unaddressed.[96] By limiting the obligation to unbundling of accounting, the Directive failed to effectively separate the generation and transmission activities of vertically integrated companies, which is considered crucial for achieving competition in wholesale electricity markets. Evidence accumulated that the access regime did not work properly.[97] Vertically integrated companies used their network assets to make entry more difficult for competitors.[98] The limited rules on unbundling did not resolve the fundamental conflict of interest within these companies relating to the interest of their generation branch in maximising sales and market shares and the obligation of network operators to offer non-discriminatory access to competitors. Finally, the absence of any measure mitigating the high market concentration[99] of incumbent generation firms discouraged competition and new entry. Worse still, the barely concealed intent of many Member States to favour so-called 'national champions' favoured a wave of mergers that led to even higher market concentrations of incumbents. In the majority of Member States competition remained limited to former monopolists.[100]

from that source. See European Commission, Decision of 8 July 1999, O.J. L 1999 319/11; Cameron (2002: 6.33).

[94] One of the reasons for the relative lack of concern of the legislator for environmental aspects was the lack of cooperation between the Energy Council and the Environment Council. See for more information on the integration of environmental concerns in other policies of the EU Pallemaerts et al. (eds.) (2006).

[95] See in particular recital 4, Article 5 (1b), Article 8 (3), Article 3 (2) and Article 11 first E-Directive.

[96] According to Jamasb and Politt, two leading economists in this field, experience has shown that liberalisation requires the implementation of one or more of the following inter-related steps: sector restructuring, introduction of competition in wholesale generation and retail supply, incentive regulation of transmission and distribution networks, establishing an independent regulator, and privatisation. See Jamasb et al. (2005: 2).

[97] European Commission, COM (2001) 125.

[98] COM (2007) 528.

[99] This could happen through so-called 'horizontal splitting'. See Jamasb et al. (2005: 2).

[100] According to Cameron, 'the market power of incumbents has increased and the entry of new players into the electricity markets has taken on a "waiting for Godot" aspect'. See Cameron (ed.) (2005: 2.79).

Significant problems also resulted from the patchy implementation of the Directive.[101] Furthermore, cross-border trade remained limited due to congestion at the borders, insufficient development of interconnectors between national grids and the considerable variation in technical standards relative to the operation of networks.[102] Finally, the liberalisation led to the creation of a patchwork of national regulatory entities with widely differing supervisory powers.[103]

With respect to the environment, the Commission considered that the liberalisation had been largely positive, but recognised that potential price declines might undermine energy-saving efforts and make new renewable energy sources and combined heat and power less attractive.[104] To address some of these problems the Council and the European Parliament adopted within the framework of the European Climate Change Programme (ECCP) a Directive on the promotion of electricity produced from renewable energy sources in 2001,[105] a Directive establishing a scheme for trading in greenhouse gas emission allowances[106] (the 'ETS'), a Directive on Energy Taxation,[107] a Directive on the promotion of co-generation in 2004[108] and finally a Directive on energy-efficiency and energy services in 2006.[109]

3. The first revision 'package'

To deal with the economic shortcomings of the first regulatory regime, the European Council at its meeting in Lisbon of 23-24 March 2000 called for 'rapid work' to speed up liberalisation in the electricity market.[110] In 2003 a revised Electricity Directive[111]

[101] Some Member States had elected to go beyond the minimum requirements of market opening, whereas others had not. See Cameron (ed.) (2005: 9).
[102] One of the reasons for the insufficient progress made in cross-border trade is that incumbents have little interest in interconnectors between the different national grids as this enhances competition and will finally erode their monopoly rent. See COM (2007) 195 final.
[103] Germany was the only country which did not foresee the creation of a national regulatory authority but entrusted the supervision of the market to its competition authorities. See Cameron (ed.) (2005: 2.65).
[104] COM (2001) 125.
[105] Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market, O.J. 2001 L 283, p. 33–40.
[106] Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for trading in greenhouse gas emission allowances within the Community and amending Council Directive 96/61/EC, O.J. 2003 L 176/37.
[107] Council Directive 2003/96/EC of 27 October 2003 restructuring the Community framework for the taxation of energy products and electricity, O.J. 2003, L 283/51.
[108] Directive 2004/8/EC of the European Parliament and of the Council of 11 February 2004 on the promotion of cogeneration based on a useful heat demand in the internal energy market and amending Directive 92/42/EEC, OJ 2004 L 52/50.
[109] Directive 2006/32/EC of the European Parliament and of the Council of 5 April 2006 on energy end-use efficiency and energy services, OJ 2006 L 114/64. The content of these Directives will not be discussed here. Where appropriate, reference will be made to certain of their provisions.
[110] COM (2001) 125.
[111] Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC, O.J. L 176,

and a new regulation on cross-border trade in electricity ('Cross-Border Directive') entered into force.[112] A year and a half later, a Directive aiming at safeguarding security of supply and infrastructure investments completed the reform 'package' ('Security of Supply Directive').[113]

a) The second Electricity Directive

The second Electricity Directive has two principal aims: to bring about full market opening by 2007 and to enhance the quality of regulation through greater uniformity and coordination of national regulation.[114] Generally, more attention is granted to issues related to the environment.

The problems relating to network access are addressed by a clear commitment to 'regulated' TPA for both transmission and distribution.[115] To guarantee fair access to the grid, new requirements are set up regarding network tariffs. All network operators are obliged to submit their tariffs, or at least their tariff calculation methods, to a regulator for authorisation.[116] The regulator must examine the tariffs or calculation methods to ensure that these are non-discriminatory and reasonable, and alter them where necessary.[117]

Unbundling rules are strengthened. Network operators that are part of a vertically integrated undertaking have now to be independent from other activities not related to transmission in terms of their legal form, organisation and decision-making.[118] However, no change in ownership of assets is required. Operators of both transmission and distribution networks must publish an annual report to the national regulatory authorities (NRAs) regarding the observance of the unbundling requirements.[119]

The role of the NRAs is significantly enhanced. By contrast to the first Directive, there is an obligation to set up a regulatory body, which has to be independent from the industry.[120] A set of minimal functions and competences is defined, which include, in particular, the monitoring of interconnection capacity, non-discriminated access to

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15.7.2003, p. 37-56. In the text that follows reference will be made to this Directive either just by the term 'Electricity Directive' or 'E-Directive' or, if there is a risk of confusion with the first Electricity Directive as 'second Electricity Directive' or 'second E-Directive'.

[112] Regulation 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity, OJ 2003 L 176/1**;** Cameron (ed.) (2005: 8).

[113] European Commission, COM (2003) 740; Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment, O.J. 2006 L 33/22.

[114] Cameron (ed.) (2005: 11); Cameron (2005).

[115] As a result Germany had to abandon the 'negotiated' grid access. No country had opted for the Single Buyer option. See Cameron (ed.) (2005: 13).

[116] This applies to all tariffs, from tariffs for network connection and network access to tariffs for balancing services. See Art. 20(1) and 23(2) E-Directive.

[117] Art. 23(2) E-Directive.

[118] Art. 10 E-Directive.

[119] Article 10 (2) (d), Art. 15 (2) (d) E-Directive.

[120] It is interesting to note that the independence is defined with regard to the industry and not the government. See Cameron (ed.) (2005: 2.36).

networks, effective competition and the duty to fix tariffs and to settle disputes.[121] Furthermore, NRAs have an advisory role and are required to contribute to the development of the internal market by cooperating with each other and the Commission. To facilitate this, the Commission has to establish an independent advisory group called the European Regulators' Group for Electricity (ERGEG) whose membership comprises the heads of the competent NRAs in the Member States.

Provisions on 'public service obligations' are slightly modified.[122] Member States may, in particular, intervene in the market in the interest of security of supply. Special emphasis is placed on the duty of Member States to protect end-users, especially vulnerable customers. Universal service has to be granted to all household consumers, who have a right to be supplied with electricity at reasonable and transparent prices.[123] Member States have, in particular, the option to establish a supplier of last resort, protect remote customers and extend universal service to small enterprises.

Regarding the construction of new generation installations, the Directive reduced the choice of Member States with regard to its predecessor. Priority is now given to the authorisation procedure, whereas tendering is limited to those cases where interests in security of supply and environmental protection require it.[124]

The greater emphasis placed on respect for the environment, in particular climate protection, is reflected in several new recitals and provisions.[125] Probably the most important modifications concern the provisions on public service obligations.[126] A particular focus is placed on measures aiming at enhancing transparency and information for the customer.[127] Finally, the Commission is requested to submit an overall report on the environmental impact of the opening of the electricity market[128] and the trade in electricity with third countries.[129]

b) The Cross-Border Regulation

The first Electricity Directives did not say much about cross-border trade. As markets remained principally national,[130] the Commission set up a new body in 1998 – the Electricity Regulatory Forum of Florence, which includes all the important stakeholders in the industry.[131] Its first task was to agree on a harmonised system for cross-border tariffication, to ensure the construction of new interconnection capacity and to develop

[121] Article 23 E-Directive.
[122] Cameron (ed.) (2005: 2.47).
[123] Article 3(3) E-Directive. An Annex to the Directive contains a list of consumer protection measures.
[124] See Article 7 E-Directive.
[125] See, for instance Art. 6 (3) E-Directive.
[126] Article 3 (1) E-Directive.
[127] Article 3 (6) E-Directive.
[128] Article 28 (1) (b) E-Directive.
[129] Article 28 (1) (f) E-Directive.
[130] Cross-border trade did not exceed 8%.
[131] The stakeholders of the Florence Forum are Member States' representatives, regulatory authorities, the European Commission, Transmission System Operators, electricity suppliers, network users, traders and consumers.

fair criteria for allocating existing cross-border capacity.[132] Rapid progress was made, but the soft law character of the Forum's guidelines made them difficult to enforce. To enhance legal certainty as well as transparency in decision-making in the ambit of cross-border exchanges, the Community decided to set up a new Regulation drawing on the rules elaborated by the Forum.

c) The Security of Supply Directive

Adopted at the end of 2005, the Directive on security of electricity supply and infrastructure investment has a double scope. It invites Member States to define standards for the security of their power networks and seeks to increase interconnections between countries to enable effective competition.[133] It requests, in particular, that TSOs submit regular investment plans for cross-border interconnectors to their national regulator, which in turn have to report yearly to the Commission.[134]

4. The second revision 'package'

Notwithstanding the legislative changes, vertical integration and high market concentration continue to hamper the development of meaningful competition. Numerous customers continue to lack a real choice of supplier and the electricity market remains fragmented along national borders. To address these shortcomings, the Commission conducted a sector competition inquiry, an in-depth review of all national electricity markets, and carried out in parallel an impact assessment related to the completion of the electricity market. It came to the conclusion that further reforms were necessary.[135]

Based on the conclusions of the European Council of March 2007,[136] the Commission set out new proposals in September 2007 to reform the electricity market within the framework of the so-called 'energy package': a revision of the second Electricity Directive,[137] a revision of the Cross-border Regulation[138] and a proposal for a Regulation establishing an Agency for the Cooperation of Energy Regulators.[139] The principal reforms aim at increasing the separation of supply and production activities from network operation,[140] enhancing the role of national energy regulators,[141] providing for a

[132] European Commission, COM (2001) 125.
[133] European Commission, COM (2003) 740.
[134] See for a critical discussion of the Security of Supply Directive Zhang (2004).
[135] European Commission, COM (2006) 841.
[136] European Council, 8/9 March, 2007, 7224/1/07 REV 1.
[137] European Commission, COM (2007) 528.
[138] European Commission, COM (2007) 531.
[139] European Commission, COM (2007) 530.
[140] Notwithstanding their strengthening, unbundling provisions remains insufficient to ensure fair access conditions to the grid for independent electricity providers. According to the Commission, better access for competitors can only be realised by full ownership unbundling. Given the strong opposition to this option by certain Member States the Commission proposes an alternative possibility, the so-called 'Independent System Operator' option. See European Commission, COM (2007) 530.

European regulatory oversight and creating a mechanism enabling transmission operators to cooperate in setting standards.[142] Other proposals seek to enhance market transparency[143] and improve the conditions for the emergence of a true retail market.[144]

In parallel to these reforms, in January 2007 the Commission proposed a so-called 'climate package',[145] which led to the adoption of important commitments to protect the climate at the European Council of March 2007.[146] In addition to its pledge to reduce its greenhouse gas emissions by 20% by 2020,[147] the European Council proposed to increase the share of renewable energy sources to 20% and to increase energy efficiency by 20% by 2020. Based on these commitments, in November 2007 the Commission proposed a Strategic Energy Technology Plan (the 'SET-Plan')[148] and in January 2008 a new package of measures,[149] including a Proposal for a Decision to meet the Community's greenhouse gas reduction commitments up to 2020,[150] an amendment to the ETS,[151] a Communication[152] and a Directive Proposal on CCS[153] and an amendment to the Res-Directive.[154]

II. The impact of the European liberalisation process on CO_2 emission trends of the power industry

The European liberalisation process fundamentally modified the way electricity utilities are managed and regulated. Its impact on CO_2 emissions varies from country to country

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[141] The Commission wants to strengthen the powers of national regulatory authorities, enhance their independence with respect to the government and give them a clear mandate to cooperate at the European level. Moreover, the Commission suggests that an independent European Agency for Energy Regulators should be created with the aim of keeping a regulatory oversight of the cooperation between transmission system operators, handling cross-border issues and keeping a general advisory role vis-à-vis the Commission. See European Commission, COM (2007) 530.

[142] An important impediment to the creation of an internal market is the wide variety of technical rules applying to electricity companies operating in the different Member States. To facilitate a process of convergence and harmonisation of grid standards, the Commission proposes to strengthen the cooperation between transmission system operators. See European Commission, COM (2007) 528.

[143] One important obstacle that impedes the creation of a competitive market is the fact that incumbents have better access to information than new entrants, in particular regarding forecasts of demand and supply, costs for balancing the network and trading. The publication of these data is hence crucial if new entrants are to be given a fair chance to compete. See European Commission, COM (2007) 528.

[144] The retail market concerns households and small PMEs. The current practice whereby households pay a final bill at the end of the year is unlikely to foster people's awareness of domestic energy consumption. The Commission hence suggests that a retail forum is created to examine how information conveyed to customers may be improved. See European Commission, COM (2007) 528.

[145] European Commission, COM (2007) 2.

[146] European Council, 7224/1/07 REV 1.

[147] This target is expressed with respect to levels of greenhouse gases in 1990.

[148] European Commission, COM (2007) 723. The SET-Plan was adopted by the Council on 28 Feburary 2008. See Council of Ministers, 28 February 2008, 6722/08 (Presse 45).

[149] European Commission, COM (2008) 30.

[150] European Commission, COM (2008) 17.

[151] European Commission, COM(2008) 16.

[152] European Commission, COM (2008) 13.

[153] European Commission, COM(2008) 18.

[154] European Commission, COM (2008) 19.

and depends on many variables, such as the mode of implementation of the Directive, the prevailing energy mix, the national regulatory framework, in particular taxes and subsidies, and the degree of competition.

Notwithstanding these differences, liberalisation has certain consequences that are similar in all Member States. In the following section we shall analyse how the principal rules laid down by the European legislator influence demand patterns and shape operation and investment conditions as well as the regulatory environment. Particular emphasis will be placed on the risks faced by investors in new power generation as these will determine emission trends in the future. An assessment of the main trends observed in the European power industry since the introduction of competition will round off this section.

Before addressing these issues, a short overview is given on the energy mix of the European power industry, the technical and economic characteristics of the main generation technologies and their carbon intensity when producing electricity.

A. Power generation and its carbon intensity

1. The energy mix of power generation in the European Union

The energy mix varies significantly in the 27 Member States.[155] The differences are the result of a multitude of factors, among which the most important are the availability of natural resources, fuel prices, technical knowledge and environmental concerns. Some events in the past, however, have contributed to shaping the energy mix of most Member States. For instance, the oil price shocks in the 1970s led to sharp reductions in the share of oil-fired and gas-fired generation in most OECD countries.[156] As a result, the use of coal increased, but the largest gains were made by the nuclear sector whose share grew from 4% in 1973 to 20% in 1985. After the Chernobyl incident in 1985, environmental concerns brought the construction of new nuclear power stations in most OECD countries to a halt.[157] At the same time, the decline in gas-turbine costs and low prices for natural gas increased its competitiveness.[158]

Overall, electricity and heat production are responsible for 24% of greenhouse gas emissions of the EU.[159] In 2004, conventional thermal energy fuelled by coal, gas and oil emitted most of them, with a share of almost 54% for electricity production.[160] Coal and lignite accounted for 29.5%, gas for 20% and oil for 4.5%. The second-largest source was nuclear energy, which generated with 31% almost a third of the EU's electricity. Together, these sources contributed about 85% of the total production, leaving the

[155] See European Commission (2005b: 9).
[156] IEA (2006: 171).
[157] A notable exception is France.
[158] IEA (2006: 173).
[159] This figure includes public electricity and heat production. See EEA (2007d: 64).
[160] See EEA (2007b). It is noteworthy that the percentages recorded by the European Commission are slightly higher for thermal electricity production, i.e. 56.8% of gross electricity production in 2003. See European Commission (2005b: 4).

remainder for renewable electricity production.[161] Large hydropower plants still dominated electricity production from renewable sources in most Member States, with approximately a 70% share across the EU-25 in 2004, compared to around 15.6% coming from biomass and waste, 13.4% from wind and the rest from geothermal (1.3%), and solar (0.2%). The share of electricity from cogeneration, allowing the combined generation of electricity and heat in a single, integrated system, was 10.2%.[162]

2. The technical and economic characteristics of power generation

a) Coal power

Coal power plants have an average lifetime of about 40 years.[163] It is a very mature technology with large investment costs and long lead and payback times. A significant part of the current power plants in the EU will have to be replaced in the next 20 years.[164] The current leading technology for coal power generation is pulverized fuel (PF) combustion steam cycles.[165] Whereas power plants older than 20 years have an average net efficiency of 29%,[166] the best coal-fired plants currently in use achieve 45 to 47% efficiency.[167] It is expected that technological advances may improve efficiencies up to 55% by 2020.[168] Irrespective of the technology used, the efficiency of power plants also depends on the quality of the fuels used,[169] on environmental standards[170] and the mode of operation, the so-called load factor.[171]

A fundamental new technique has been developed recently, the integrated coal gasification combined-cycle (IGGC). This technology allows the co-firing of coal with all carbonaceous feedstock, thus including renewables such as biomass and solid waste. High capital costs and a number of technical issues, however, get in the way of a massive deployment of this technology.[172] To significantly reduce the level of CO_2 emissions, coal power plants may be equipped with a technology commonly called 'carbon capture

[161] EEA (2007c: 3).
[162] This figure was reached in 2004. Cogeneration is significantly higher in the new Member States (15.8%) than in the pre-2004 EU-15, where it was 9.5%. See EEA (2007e).
[163] See Markewitz et al. (2005: 206).
[164] See IEA (2006: 171):
[165] Pulverised coal combustion (PCC) accounts for about 97% of the world's coal-fired capacity. The main technique is steam power. See IEA (2006: 181).
[166] The current average efficiency in Europe is 38%. See Ruelle (2006: 317).
[167] See IEA (2006: 179 ff.).
[168] Markewitz et al. (2005: 207).
[169] There are two fundamentally different types of coal, brown coal (lignite) and hard coal. Whereas the efficiency of power plants fuelled by brown coal was lower in the past, the techniques have improved lately and caught up with the efficiency of hard coal. See IEA (2006: 179).
[170] Cleaning the flue gases generated by the electricity generation in coal-fuelled power stations requires energy and hence lowers their efficiency. See IEA (2006: 180)
[171] If plants run at widely varying loads, the efficiency of fossil-fuel plants may fall considerably. See IEA (2006: 180).
[172] See IEA (2006: 181).

and storage' (CCS).[173] Carbon dioxide may be captured by a variety of methods which are classified as post-combustion,[174] pre-combustion[175] and oxy-combustion.[176] Post-combustion and pre-combustion methods currently collect 85–90% of the CO_2 and oxy-combustion plants 90-97%, but they reduce the thermal efficiency of a plant.[177] It is generally considered that at least ten major power plants fitted with capture technology must be operating before a large-scale diffusion of the technology can be envisaged.[178]

b) Gas power

Gas power stations have been used for electricity generation since the 1980s.[179] They originally had an efficiency of about 35% and were made of steam turbines. The introduction of combined-cycle steam and gas units significantly improved the plants' efficiency, with the best available ones reaching up to 60% today.[180] The combined-cycle gas technology has rather low investment costs and short construction times.[181] In the early 1990s, new gas-turbine stations were usually the aggregation of generators on a single remote site, essentially equivalent to traditional steam-turbine stations.[182] Gradually, however, gas-turbines were built closer to loads and in much smaller sizes. Very easy to start and shut off, gas power plants are ideal for peak load and backup power.

c) Nuclear power

Nuclear reactors are classified by their neutron energy level into thermal reactors and fast breeder reactors,[183] as well as by reactor 'generations'.[184] A new technology based on fusion is currently being explored.[185] Although high shares of public funds for R&D are invested in this technology, its deployment is not likely until at least 2050. The

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[173] It involves three distinct phases: the separation of the CO_2 from the fuel, the transport of the CO_2 and its storage underground. See IEA (2007: 1).

[174] Post-combustion capture uses a solvent to capture CO_2 from the flue gas of power plants. IEA (2007:2).

[175] In pre-combustion capture the fuel is reacted with air or oxygen and then with steam to produce a mixture of CO_2 and H_2. See IEA (2007: 3).

[176] Oxy-combustion is when oxygen is used for combustion instead of air. See IEA (2007:4).

[177] IEA (2007: 5).

[178] The cost of these demonstration plants is expected to range between US$ 500 and US$1 billion each, of which 50% accounts for the additional costs of CCS. See IEA (2006: 199); European Commission, COM (2008) 13, COM (2008) 18.

[179] Gas turbines originally powered aircraft. See Patterson (2007: 48).

[180] The global average efficiency of natural gas fired plants increased from 35% in 1992 to 42% in 2003. See IEA (2006: 178)

[181] Gas-power stations may be built within two years or even less. See Patterson (2007: 56).

[182] Patterson (2007: 48).

[183] Fast breeders have received only limited market support despite their efficiency in the use of uranium. As uranium remained cheap, there was little incentive to use this new technology. Apart from uranium, thorium can also be used as nuclear fuel.

[184] Generation III reactors were developed in the 1990s. They are standardised or modular to facilitate licensing, reduce capital costs and reduce construction time. Moreover, they are safer and have a longer operating life (typically 60 years). See IEA (2006: 234).

[185] Fusion is a nuclear process that releases energy by joining together light elements, the direct opposite of fission. IEA (2006: 245).

construction of nuclear plants involves an up-front investment ranging from €2 to €3 billion and their lead times range from 5 to 10 years.[186] Operation and maintenance are estimated to amount to 30% and fuel cycle costs to 20% of overall costs.[187] Relatively inflexible, nuclear energy is essentially used for baseload.

Since the Chernobyl accident, the nuclear industry has made considerable investments to improve the level of security. Concerns relating to the safety of nuclear plants, proliferation and waste management, however, remain important.[188] Accordingly, certain European countries such as Germany, the Netherlands, Spain, Sweden and Belgium have so far remained committed to phasing out existing plants.[189] By contrast, other countries such as France, Finland and the UK have demonstrated renewed interest in building new nuclear power plants.[190]

d) Large-scale renewable energy sources

Large hydropower is a mature and extremely flexible technology with long lead times and large investment costs, yet operating costs are very low.[191] Undesirable environmental and social effects, however, represent important barriers to its further development. In Europe, the potential for the construction of new plants is limited, as the most suitable sites have already been exploited.

The construction of large offshore wind parks is characterised by high upfront costs, significant technical risks and the necessity to reinforce existing high voltage grids to transport electricity to load centres. Unlike onshore wind, it is not yet a well proven and widely-deployed technology.[192]

e) Cogeneration

Combined heat and power (CHP) systems, also known as cogeneration, generate electricity and thermal energy in a single, integrated system.[193] CHP is far more energy efficient than separate generation of electricity and thermal energy.[194] Heat that is normally wasted in conventional power generation is recovered as useful energy for satisfying an existing heat demand. CHP is most efficient when the heat can be used on

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[186] The costs as well as the lead times differ significantly from country to country. Where licensing processes are relatively immune from outside interference as in France and Finland, costs are much lower and planning and construction times can be limited to 5 years. See Joskow (2006).
[187] IEA (2006: 240).
[188] The nuclear fuel cycle includes several steps, from uranium mining to the disposal of spent fuel and radioactive waste from reprocessing.
[189] See for a critical discussion of nuclear power and climate change Matthes (2005).
[190] In early 2006, there were 443 nuclear plants in operation in 30 countries. Most of the plants were built in the 1970s and 1980s. A six-fold increase is, for instance, planned to take place in China and India by 2030. See IEA (2006: 233); Bupp et al. (2006).
[191] IEA (2006 : 214)
[192] See EWEA (2007b).
[193] Brooks et al. (2006a :1)
[194] Compared to divided processes and technologies of power generation, CHP exploits the primary energy carriers most efficiently. Energy savings of up to 36% are possible. See www.chp-info.org.

site or very close to it. Almost all energy sources (i.e. natural gas, heating oil, coal, waste, biomass) can be utilised. CHP technology comes in all sizes, but in most cases it is middle or small-sized. A clear distinction must be made between industrial and district heating. Whereas industrial CHP is installed by industries with an considerable demand for heat, district heating supplies from several buildings up to entire cities.[195]

f) Distributed generation based on fuels

In the 1990s, technological progress allowed the installation of ever-smaller units of electricity generators, also commonly called 'distributed generators'. Based on petrol, diesel, or gas, the new devices became popular especially for on-site cogeneration.[196] They provide electricity down to a kilowatt of electricity plus hot water, a size suitable for an individual household.[197] One further option for fuel-based electricity is the fuel cell. Many different kinds of fuel cell have been developed, with outputs adequate for a personal computer. Two factors still hamper their wide-scale application: the need for hydrogen or its production nearby and the necessity to bring down costs.[198]

g) Small renewable energy sources

The greatest success of all small-scale renewables is wind power. Its growth is closely related to the size of its turbines, the diameter of which has increased from 10 metres in the mid-1970s to 126 metres today.[199] Costs have declined steadily and depend on system components and size, as well as on the site.[200] Challenges to future deployment include grid integration, forecasting of wind availability, improvement of storage capacity and visual impact.

Another widespread and rapidly expanding technology is photovoltaic (PV) electricity, which uses cells that convert light directly into electricity. PV cells, the investment costs of which account for approximately 97% of total costs, have an expected lifespan of between 20 to 30 years.[201] So far, solar thermal electricity, which concentrates the sun's

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[195] The 'new' Member States traditionally have a much higher percentage of district heating. However many of these systems, which are a legacy of former Communist regimes, need to be modernised.
[196] Some examples: Stirling engine, microturbine.
[197] See Patterson (2007: 49).
[198] See Patterson (2007: 50).
[199] Wind energy accounted for 32% of all electricity generation installed between 2001 and 2006 in the EU. Of the countries in Europe, Germany has the largest amount of installed capacity, followed by Spain and Denmark, with a contribution of 5%, 8% and 19%, respectively, to domestic electricity needs. See EWEA (2006: 6); IEA (2006: 219).
[200] IEA (2006: 219).
[201] Whereas a number of technologies are in the commercial stage, many others are still in the laboratory phase. PV technologies are mainly supported by Japan, Germany and the US, which account for about 85% of global PV capacity. Costs for PV systems vary widely and depend on the system's size, location and the grid connection. See IEA (2006: 223).

rays to produce steam for a turbine, has not yet achieved the same success. In Member States with high annual insolation it could become a significant technology.[202]

Biomass is the most significant source of renewable energy after large hydro. It encompasses a wide variety of feedstock, including wastes from forest products, agricultural residues and municipal wastes.[203] It is a relatively flexible technology with an average energy efficiency of about 22%, but may achieve efficiencies of up to 45% in modern coal power plants allowing co-firing.[204]

A technology with a considerable potential, which has as yet been little exploited, is run-of-the river electricity. Unlike large hydro, it is environmentally relatively benign. Other water-related technologies, such as wave and tidal energy, are still in an early phase of development.

Finally, geothermal power, which uses heat stored beneath the Earth's surface, is a quite mature technology, providing a reliable base-load.[205] Up-front investments, which fell by almost 50% between the mid-1980s and 2000, make up a large share of overall costs of generation. Challenges to expanding geothermal energy include long project development times, the risk and cost of exploratory drilling and undesirable environmental effects.[206]

With the exception of small hydro, biomass and increasingly on-shore wind, small-scale renewables are still relatively immature technologies that will require important R&D efforts as well as large-scale deployment to drive down costs enough for them to become competitive. In general they have rather high up-front and low operation costs.[207] Nearly all small-scale renewables feed directly into the distribution network. Wind, solar, run-of-the river, wave and tidal energy[208] present an intermittent character.[209]

3. The carbon intensity of power generation

Brown coal power plants emit by far the greatest amounts of CO_2, with emissions ranging between 850 and 1200g CO_2/kWh, depending on the type of plant, the quality of the coal and the methodology used to calculate them.[210] It is followed by hard coal with emissions

[202] See Patterson (2007: 51).
[203] IEA (2006: 209 ff).
[204] Cost may vary significantly according to the technology, the fuel costs and the fuel quality. Its mitigation potential is significant, but may be adversely affected by long transport distances and intensive farming See IEA (2006: 209)
[205] IEA (2006: 217).
[206] Geothermal energy contributed only 5% towards total renewable energy consumption (and 0.3% of total energy consumption) in the EU-25 in 2004, with Italy accounting for around 90% of this. There is still significant potential to exploit geothermal heat, particularly in the form of heat pump technology. See EEA (2007c).
[207] Biomass represents an exception, with higher operation costs.
[208] The capacity of hydro power depends very much on weather conditions.
[209] Neuhoff (2005: 92).
[210] The determination of CO_2 emissions resulting from the various generation technologies cannot be pinned down to one precise value as they depend on the methodology, the life-cycle-assessment and other

of 750–1100g CO_2/kWh, gas with emissions of 400–550g CO_2/kWh, photovoltaic with emissions of 50–100g CO_2/kWh, hydro with emissions of 10–40g CO_2/kWh, wind with emissions of 10–40g CO_2/kWh, nuclear with emissions of 10–30g CO_2/kWh and solar thermal with emissions of 10–14g CO_2/kWh. The emissions of biomass are difficult to calculate and depend very much on the generation technology. Studies indicate a range between – 580 g and + 156 g CO_2/kWh.[211]

These figures show that coal is the main cause of CO_2 emissions, followed by gas. Thus Member States where a large share of power comes from fossil fuel such as Luxembourg and Germany usually have far higher 'per capita' emissions than countries where a large percentage of power is generated from nuclear and/or hydro energy, like France and Sweden.[212] As coal power plants emit on average twice as much CO_2 than gas power plants, a switch from coal to gas can already lead to large reductions in CO_2 emissions.[213] Significant reductions may, moreover, be attained by replacing ancient power stations with more efficient plants[214] or by co-generation.[215] A more radical decrease of CO_2 emissions such as will be necessary to keep the increase in global temperature below 2 °C above pre-industrial levels will, however, be possible only if fossil fuel power plants are equipped with CCS and/or to a large extent replaced by generators that use renewable energy sources or nuclear power[216]. As the still small share of power generation from 'new' renewables[217] demonstrates, the task is immense and will not be achieved in the short-term.

B. The main changes resulting from liberalisation and their impact on CO_2 emissions

Whereas current CO_2 emissions essentially depend on how many hours the various generation units of the power generation plant are in use and at what load factor, future CO_2 emissions will be shaped by demand patterns, research and investment decisions. In the following section we shall thus describe the main changes arising from the European liberalisation process and try to evaluate their effect on the consumption of electricity, the various power technologies and CO_2 emissions in the EU.

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factors, which vary from study to study. Burckhardt et al. present a good overview of the main studies, which have been undertaken to determine the carbon intensity of power generation. See Burckhardt et al. (2007: 495); IEA (2006: 182).

[211] The negative values for CO_2 emissions are linked to CHP-plants and take into account the avoided methane emissions which would have occurred if the biomass had fermented. See Burckhardt et al. (2007: 494).

[212] See for a table of CO_2 emissions per capita http://www.swivel.com/data_sets/spreadsheet/1005776; see for 'emission intensities' Baumert (2005: 25).

[213] See Keay (2005).

[214] See below the efficiency grades of the various fossil fuel power plants.

[215] See for the mitigation potential of cogeneration Keay (2005); D'Haeseleer (2005).

[216] The construction of nuclear plants is very controversial due to the other environmental risks of this technology. Its mitigation potential is, however, important. See for a critical view on the mitigation potential of nuclear energy Fritsche (2006).

[217] 'New' renewables refer to renewable energy sources other than large hydro power.

1. Rise of electricity demand

At the heart of the liberalisation agenda lies the idea that the introduction of competition will encourage the use of power plants to produce more electricity at lower prices. Lower prices will reduce incentives to save energy. The second Electricity Directive addresses this trade-off by allowing the recourse to energy efficiency and demand-side management measures, which are aimed at influencing the amount and timing of electricity consumption to reduce consumption and peak loads by giving precedence to investments in energy efficiency or equivalent measures over investments in generation capacity.[218] These measures may be taken in three well-defined circumstances. First, Member States may impose them as a public service obligation[219] on undertakings operating in the electricity sector. Second, Member States can put in place a tendering procedure for them in the interests of environmental protection if the same goal cannot be attained by the authorisation of new generation.[220] Third, DSOs are invited to 'consider' them if they contribute to avoiding an upgrade or replacement of network capacity.[221] The implementation of all three measures is optional and may only be take place if such a measure is 'the most effective and economical option, taking into account the positive environmental impact of reduced energy consumption, security of supply and distribution cost aspects'.[222]

Given the incentives of electricity generators to increase their production to maximise profits, it may be questioned whether these provisions will lead to significant energy savings. This is recognised by the EE-Directive which states that 'liberalisation has not led to significant competition in products and services which could have resulted in improved energy efficiency on the demand'.[223] To offset this trend, the EE-Directive mandates Member States to take a series of energy efficiency measures.[224]

Liberalisation, however, does, not result only in an increased demand for electricity; it also gives customers a greater choice. It opens the way for consumers to select the type of generation technology they desire based on costs, environmental performance or other criteria such as the time of supply.[225] A costumer with an electric car may, for instance, choose to enter into a contract with a producer of wind energy, which stipulates that he or she may reload the car battery during the night when power is abundant and demand scarce. To make an informed choice, consumers must, however, have true supply alternatives and receive adequate information about the origin of the electricity

[218] The distinction between energy efficiency and demand-side management measures is an important one. Whereas energy efficiency measures lead to a reduction of consumption, this is not always the case with demand-side management measures, which might only bring about a reduction of peak electricity without any reduction of energy consumption.
[219] Article 3 (2) E-Directive.
[220] Article 7 (2) E-Directive.
[221] Article 14 (7) E-Directive.
[222] See Article 2 (29) E-Directive.
[223] See recital 9 of EE-Directive.
[224] See Article 6 E-Directive.
[225] Llamas (2000: 29).

consumed.[226] To facilitate this, the Electricity Directive mandates Member States to provide the consumer with information regarding the contribution of each energy source to their overall energy mix and its impact on CO_2 emissions and radioactive waste.[227] If this measure is a useful tool to educate citizens and to increase their awareness about the environmental consequences of electricity consumption, its positive impact on CO_2 emissions has yet to be demonstrated.[228]

Finally, due to clearer price signals, liberalisation should eventually lead to increased elasticity of demand. If this is the case, peak load will be reduced as demand adjusts to price signals. Such an evolution presupposes, however, that electricity contracts reflect the increased production costs at times of peak load and consumers have adequate metering equipment at their disposal. This is as yet rarely the case in retail markets.[229] To encourage demand response the EE-Directive requests Member States to ensure that customers are provided with 'competitively priced individual meters' reflecting their energy consumption and the time of use.[230]

The reduction of peak load, commonly called 'peak-shaving', has no clear-cut effect on CO_2 emissions. As Fowlie points out, the shift of electricity consumption to off-peak periods does not necessarily lead to lower emissions, especially if the new pricing mechanisms increase overall load factors and/or if the cheaper baseload is provided by coal plants.[231] On the other hand, price hikes may encourage customers to take measures to increase energy efficiency and to have recourse to small-scale renewables.[232]

2. Pressure on electricity prices

One of the principal reasons for introducing competition in the electricity sector was that the overall increase of efficiency and the (partial) transfer of decision-making from public to private operators would exert pressure on electricity prices.[233] Economic theory suggests that, in a perfectly competitive market, prices reflect the short-term marginal cost of the marginal plant, which is the plant that is needed to generate the last kWh to meet demand.[234] A requisite for competition to be successful in driving down prices is,

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226 IEA (2003).
227 Article 3 (6) a, b E-Directive.
228 Empirical studies show that the amount of switching by consumers to 'green' electricity is small in the absence of economic incentives. See Salmelaand et al. (2006).
229 Italy represents an exception; about 30 million meters are currently about to be installed there. See www.metering.com
230 See Article 13 EE-Directive.
231 According to Fowlie it has been demonstrated that load factors will increase under retail competition, as suppliers employ new pricing mechanisms to maximise sales opportunities and shift demand to off-peak periods. See Fowlie (1999: 31).
232 The installation of local solar power may constitute a competitive alternative for peak load in hot summers.
233 In contrast to public authorities, private parties are not expected to internalise externalities, unless explicitly requested to do so by regulation. See Llamas (2000: 28).
234 The short-term marginal costs of a plant are mainly those for fuel, operating and management, but do not include the capital cost of the investment. Short-term marginal prices are hence not sufficient to guarantee the renewal of the production capacities. See Leprich (2005: 2).

however, that a suitable market structure is set up within which effective competition can be established.[235] This is not yet the case in most Member States, where the significant market power exerted by incumbents keeps prices well above competitive levels.[236] Moreover, as demand elasticity has remained low, prices have become extremely volatile.[237]

The general pressure on prices is usually negative for energy efficiency measures and producers of renewable electricity, as the former become economically less attractive and the latter have to fight harder to become competitive. To the extent that prices remain above short-term marginal costs, these consequences are, however, somewhat mitigated in the European electricity market.

3. Pressure on costs

Under the traditional model, electricity prices were fixed by regulatory formulae, which ensured that utilities recovered all their costs. Accordingly, little emphasis was placed on cost reductions. In a liberalised environment, this is no longer the case. As the price of electricity is determined by the market, competitive pressure is exerted on utilities to increase efficiency and reduce charges. To achieve these goals, utilities embrace several strategies. An important item of expenditure is generally equipment, the costs if which can be significantly lowered through competitive procurement. Fuel costs may be reduced by increasing plant efficiency, changing the fuel mix, making improvements in fuel contracting or by the construction of multi-fuel power plants which allow advantage to be taken of relatively brief changes in fuel prices.[238] A decrease in operation and maintenance costs is achievable through a greater emphasis on economical design, an increase in capacity utilisation and the minimisation of outages.[239] Finally, utilities will lobby hard to keep charges resulting from environmental legislation to a minimum.

The overall impact of the pressure of costs on CO_2 emissions is mixed. While the increased supply-side efficiency certainly helps to reduce fuel input, switches to the cheapest fuel and the downward pressure on environmental standards may offset the positive effects for the environment of increases in supply-side efficiency.

4. Development of networks

[235] Generally, this involves a restructuring of the sector, including the unbundling of vertically integrated operators, a reduction of horizontal market concentration, the establishment of liquid and transparent wholesale and retail markets and the creation of interconnections with other systems. See Jamasb et al. (2005: 2).

[236] See COM(2006) 851; Leprich (2005: 2).

[237] If demand exceeds available capacity the price is equal to the level of the last opportunity cost of consumption. This is the price level at which a consumer prefers to forego rather than consume. See Lévêque (2007: 5).

[238] Pfaffenberger et al. (1999: 38).

[239] By contrast, capital costs are generally higher than under monopoly conditions, as the cost of equity and debt finance, especially for private investors, increases. See Pfaffenberger et al. (1999: 10).

The introduction of competition requires the unbundling of network activities from supply and generation to guarantee equitable access to the grid for all generators.[240] This means that the investment conditions of network operators undergo a profound change, even though they remain natural monopolies. The reinforcement and expansion of the grid are no longer controlled by generators, but become the responsibility of the network operator.[241] This gives the network operator greater leeway for initiative, but makes optimal coordination between generators and network operators more difficult. A new form of cooperation has to be established to guarantee that future investments in generation are matched by investments in transmission and vice versa.[242]

The first Electricity Directive left the regulation of network development essentially to be guided by the principle of subsidiarity.[243] Many Member States, spurred on by efficiency considerations, introduced reforms aimed at changing the financial incentives of the network regulator, replacing the traditional rate-of-return approach by so-called incentive regulation.[244] This type of regulation, which includes in particular revenue-cap and price-cap[245] regulation, encouraged a management style based upon short-term cost minimisation.[246] Over time, it became clear that the benefits of these new forms of regulation were often confined to "sweating" existing assets and would not address many of the new challenges faced by networks in the liberalised European electricity market.

The emphasis placed on cost reductions discouraged, in particular, structural changes and the adoption of the innovative technologies necessary to transport large quantities of distributed generation such as small and intermittent renewable energy sources.[247] To cope with the specificities of these technologies, new approaches in the design and the operation of the grids are necessary. Whereas the traditional role of networks has been to transport electricity from large power plants through high-voltage grids to the consumers, a grid with a large number of widely distributed electricity sources must be able to cope with electricity flows in both directions.[248] Distribution network operators will have to

[240] Article 10 E-Directive. See Lévêque et al. (2007: 4).
[241] Art. 10 (2) c E-Directive. See Lévêque et al. (2007: 3).
[242] See for a discussion on the difficulties of coordination between the network operator and generators Lévêque et al. (2007: 3).
[243] An exception was the rule set out by the first Electricity Directive allowing the construction of direct lines. See Article 21 first E-Directive; Article 22 second E-Directive.
[244] See Helm (2001: 300).
[245] Price cap regulation sets the maximum rate of increase for the regulated prices equal to the inflation rate of the retail prices index (RPI) minus a productivity growth offset referred to as the X-factor. See Mehdi et al. (2007: 2). As with price-cap regulation, the revenue-cap regulation system uses 'CPI − X' to set revenue caps. This takes the rate of inflation and subtracts the expected efficiency savings X. The system is intended to provide incentives for efficiency savings, as any savings above the predicted rate X can be passed on to shareholders, at least until the price caps are next reviewed. A key part of the system is that the rate X is based not only a firm's past performance, but on the performance of other firms in the industry.
[246] The main categories of incentive regulation systems used for electricity utilities are: price/revenue cap schemes, sliding-scale rate of return, partial cost adjustment, menu of contracts, and yardstick competition. See Mehdi et al. (2007: 2).
[247] Degner et al. (2006: 18); Connor et al. (2004); IEA (2002); Scheepers et al. (2004); Timpe et al. (2004); Dunn (2000); Takahashi et al. (2005); Mitchell (2000); Pepermans et al. (2005); Raineri et al. (2005); Donkelaar et al. (2005).
[248] Degner et al. (2006: 8).

transport electricity in different directions and become active providers of services between generators and consumers. This change in structure entails the coordination of a large number of systems with the electricity networks and requires the development of sophisticated information and communication technology.[249]

Second, traditional network regulation tended to obstruct rather than promote energy efficiency measures. This is because the revenues of network operators depend essentially on the number of electricity units transported, so they have no incentive to encourage measures which reduce energy flows.[250] If this is to change, the structure of network tariffs must be significantly modified and allow network operators to be compensated not only for transporting electricity but also for services leading to lower energy consumption.

Third, network operators of vertically integrated utilities showed little interest in developing new interconnection capacity as increased cross-border flows would reduce the market share of their generation branch and increase competition in their 'home' market. This attitude was in part encouraged by national regulators whose primarily national focus often hinders an optimisation of the overall development of networks.

Finally, the electricity outages during 2003 revealed a flagrant lack of common security standards and the necessity to create a coherent European framework for network investments. As these shortcomings became more apparent, the European legislator progressively adopted a series of rules that reflect an increasing awareness that network development ought not be left essentially to subsidiarity.

Whereas the first Electricity Directive barely tackled the questions that arise in connection with the absorption of small renewables,[251] the Res-Directive mandates Member States to guarantee their transport and sets out certain principles regarding the allocation of costs relative to their connection with the grid.[252] It requires in particular that rules have to be based on objective, transparent and non-discriminatory criteria, taking account of all the costs and benefits associated with the connection of these producers to the grid.[253] The 'second' Electricity Directive reiterates this principle and extends it to all distributed generation as well as to cogeneration.[254] It further invites the network operator, when planning the expansion of distribution networks, to consider whether distributed generation might supplant the need to upgrade or replace network

[249] Varming et al. (2004a and b).
[250] See Leprich et al. (2004); Leprich (2006).
[251] The first Electricity Directive stated that distribution system operators had to give due regard to the environment in the fulfilment of their tasks and foresaw the possibility of building direct lines to connect local load with local generation. See Article 11 first E-Directive and Article 21 (3) first E-Directive.
[252] See Article 7 Res-Directive.
[253] See Pepermans et al. (2005); Connor et al. (2004); IEA (2002); Scheepers et al. (2004); Timpe et al. (2004); Dunn (2000); Takahashi et al. (2005); Mitchell (2000); Raineri et al. (2005); Donkelaar et al. (2005).
[254] Article 23 (2) E-Directive.

capacity.[255] Finally, it requests the regulatory authority to set network tariffs so as to allow investments in the networks to be carried out in a manner 'ensuring the viability of the networks'.[256]

Both the RES-Directive and the second Electricity Directive, however, remain silent regarding the necessary structural changes that networks will have to undergo to ensure a large-scale uptake of renewables and to encourage energy savings and demand-side management. These issues were finally addressed, though not very concretely, by the EE-Directive and the Proposal for a revised Electricity Directive. Whereas the former asks Member States to remove those incentives in transmission and distribution tariffs that unnecessarily increase the volume of distributed or transmitted energy,[257] the latter provides for the establishment of a framework which should allow TSOs to identify, finance and manage research and innovation activities enabling the penetration of renewables and low carbon technologies into the grid.[258] Such measures are undeniably important to modify the current incentives of network regulation. It remains to be seen, however, whether they are sufficient to make grids 'smarter' and bring about a thorough modernisation of networks, which would allow the widespread deployment of small-scale generation and minimise energy consumption.

The problem of insufficient investments in interconnections and unfair rules for cross-border exchanges is addressed by the Cross-Border Regulation. To enhance cross-border trade the Regulation sets up a compensation mechanism for cross-border flows of electricity and lays down harmonised principles on cross-border transmission charges and the allocation of available capacities of interconnections.[259] It states, in particular, that transmission tariffs must take into account the need for network security and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator.[260] With this rule, the Regulation lays down the principle of cost-reflectiveness of network tariffs and ensures at the same time that the application of this principle does not reward inefficient network management and/or lead to excessive cost recovery.[261] Moreover, network tariffs may not be distance-related. A so-called postage-stamp mechanism has to be applied whatever the distance that separates

[255] This provision reflects the idea that an alternative and more environmentally friendly option to network development is a reduction of the demand through particular end-use efficiency schemes or the installation of distributed generation. See Article 14 (7) E-Directive. It is completed by recital 18 which calls upon national regulatory authorities to ensure that transmission and distribution tariffs take into account the long-term, marginal, avoided network costs from distributed generation and demand-side management measures. See on the capacity of distributed generation to reduce the necessity for upgrading distribution networks Degner et al. (2006).
[256] Article 23 (2) E-Directive.
[257] Article 10 EE-Directive.
[258] Article 22b (d), Proposal for a revised E-Directive. See European Commission, COM (2007) 528.
[259] It introduces inter-TSO compensation mechanisms to compensate for cost incurred as a result of hosting cross-border flows of electricity in their networks by TSOs from which those flows originate. Second, it encourages market-based charging for network access. Third, it sets out measures to improve capacity allocation including congestion management. See Article 1, 3, 4 and 6 E-Regulation; Cameron (2005: 29).
[260] See Article 4 (1) E-Regulation.[260]
[261] See on the merits of benchmarking Jamasb et al. (2001); Schaefer et al. (2006); Riechmann et al. (2006).

the generator from its customer and the costs incurred for the transmission of electricity. This is to ensure that contracts on cross-border transits are not discriminated against national transactions. Finally, the Regulation issues guidelines which aim at establishing a system of long-term locational signals. This means that Member States are encouraged to develop network tariffs that incentivise generation investments located in importing countries rather than in countries with overcapacity of electricity production and thus contribute to maintaining a balance between generation and consumption.[262]

The question of network security is dealt with by the Security of Supply Directive. Placing the emphasis on the necessity to encourage investments in interconnectors and a high level of operational network security, the Directive insists on the need for a high degree of central coordination in order to deliver a rational network and reduce uncertainty.[263] Member States are invited to establish a regulatory framework[264] that provides investment signals for both the transmission and distribution system network operators to meet foreseeable demand and to facilitate maintenance and, where necessary, renewal of their networks. Member States must further ensure that decisions on investments in interconnection are taken in cooperation with the relevant TSOs and in accordance with the priorities set out by the TEN-guidelines.[265] In implementing the required measures Member States may take into account the importance of renewable energy technologies and distributed generation.[266]

Both the Cross-Border Regulation and the Security of Supply Directive have been heavily criticised for the lack of concern they show for environmental protection, in particular for energy efficiency measures and renewables.[267] According to Zhang the emphasis placed by the Security of Supply Directive on the construction of more interconnections and new infrastructure is likely to offset completely any positive effects of the EE-Directive, as they unilaterally favour the satisfaction of increasing demand instead of aggressively pursuing energy savings.[268]

If it is true that both instruments primarily foster the transport of bulk electricity by high-voltage transmission lines, investments in new grid infrastructure and interconnections are an important prerequisite for the integration of renewables, in particular for intermittent sources like on- and off-shore wind.[269] The criticism is, however, justified to the extent that the Security of Supply Directive[270] and the Cross-Border-Directive leave it

[262] To generate locational signals network tariffs are ideally charged to generating companies in exporting countries and consumers in importing countries. See Recital 12, E-Regulation; Merlin (2005: 166).
[263] European Commission, COM (2003) 743.
[264] See Article 6 (1) Security of Supply Directive; Cameron (2007: 18.42).
[265] The TEN-guidelines comprise a series of guidelines covering the objectives, priorities and broad lines of action by the Community with respect to trans-European energy networks. See Decision No 1364/2006/EC of the European Parliament and the Council of 6 September 2006 laying down guidelines for trans-European energy networks, O.J. 2006 L 262/1.
[266] Article 3 (3) c Security of Supply Directive.
[267] See for a strong criticism of the Security of Supply Directive Zhang (2004).
[268] Zhang (2004: 173).
[269] See EWEA (2006); Deutsche Energie Agentur (2005); recital 5 of the Security of Supply Directive.
[270] See Articles 3(2)e, 3 (3) c Security of Supply Directive. It should be noted that the provision for renewables has even been watered down in the final version of the Directive which requires Member States

essentially to the Member States to decide whether and how they want to take environmental concerns into account when planning investments.[271] In the absence of clear guidance and mandatory requirements it is doubtful that Member States will encourage the changes necessary in network regulation to allow the large-scale deployment of renewables and the implementation of energy efficiency measures. The situation may, however, improve somewhat if the current 'energy package' is adopted, in particular if Member States opt for ownership unbundling, which would guarantee a more neutral attitude of network operators towards power generation technologies. Some prospects for improvement may also result from the efforts made within the framework of the European Technology Platform for Electricity Networks of the Future ('Smartgrids'), which aims to enhance the coordination of national research agendas regarding the modernisation of electricity networks.[272]

5. The operation of networks

The grant of non-discriminatory access to networks implies that a body is designated from among the network operators, which is responsible for its operational implementation. The Directive entrusts this task to the TSOs, who are responsible for the management of the energy flows, the provision of ancillary services[273] and efficient access to the grid.[274] The Directive further lays down specific rules regarding the dispatch of electricity, the balancing of supply and demand, and the covering of energy losses and the provision of reserve capacity.[275]

a) The dispatch of electricity

Under monopoly conditions the system operator, whose task was to maximise efficiency and system security, determined the order in which the generation units would be dispatched.[276] This involved some subjective judgement.[277] In an open market, the dispatch of electricity leaves less leeway to the TSO.[278] When dispatching electricity the TSO has to take into account the economic precedence of electricity (that is, offered

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merely to take into account renewables and energy demand reductions whereas the Commission Proposal asked for them to take 'the utmost account'. See Zhang (2004: 171).

[271] This lack of attention is partly remedied in the Proposal of amendment to the Cross-Border Directive of the Commission (recitals 1, 6 and 7 as well as Article 3 (k)). See European Commission, COM (2007) 531.

[272] The European Technology Platform 'Smartgrids' was initially set up by the Commission to allow a large-scale discussion among stakeholders on how the future European networks would have to be reformed to allow a large-scale deployment of renewable and distributed generation. See European Commission (2006a); European Commission (2007).

[273] See for a discussion on regulation of ancillary services Raineri (2006).

[274] See Articles 8-12 E-Directive.

[275] The tasks of the TSO are listed in Art. 9-11 E-Directive. See also Boisseleau (2004: 55).

[276] Jones (2004: 3.6).

[277] As a rule, power plants with low short-term marginal costs run most of the time, whereas generators with high marginal costs operate for only short periods of time, covering only peak load. See Jones (2004: 3.6).

[278] Jones (2004: 3.6).

price) from generating installations within the territory of the TSO and from outside.[279] These rules mean that electricity is dispatched to the extent that a sale contract exists or that generators have successfully bid to sell into an electricity exchange. Unless technical constraints on the system require a correction of the market, the role of the TSO is reduced to executing the decisions taken by market operators.[280]

According to Article 11 (3) E-Directive, Member States may request the TSO to give priority to generating installations using renewable energy sources or waste or producing combined heat and power.[281] This provision is somewhat deceptive. Indeed, whereas prior to liberalisation it was perfectly possible for a Member State to ask the system operator to dispatch electricity generated from renewable[282] or indigenous energy sources before others, such an obligation is difficult to implement in a liberalised market.[283] The TSO can only dispatch electricity from generators which have effectively entered into a sales contract. Unless generators of renewables or CHP are competitive or benefit from a support scheme, this rule will remain ineffective. A similar rule applies to indigenous fuels, which may be granted priority dispatch up to 15% of energy generation.[284]

Based on the principle of 'economic precedence', the dispatch of electricity favours the generation technology with the lowest market price within the control area of the TSO.[285] The so-called economic 'merit order' differs from country to country and may change over time. Usually, large hydro followed by nuclear are the most competitive energy sources.[286] The competitiveness of coal with respect to gas depends essentially on the efficiency of power plants, fuel costs and, since the launch of the ETS, also on the price for carbon and the way allowances are allocated.[287]

Few Member States have decided to accord priority to new renewables.[288] Where this is the case, the priority rule has been coupled with a system of price support, which modifies the 'merit order' in favour of these technologies.

b) The balancing of supply and demand

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[279] See Article 11 (2) E-Directive, Cameron (2007: 5.30).
[280] Glachant (2001: 6).
[281] Article 11 (3) E-Directive. An equivalent provision for distribution is Article 14 (4).
[282] By 'renewable energy sources' the Res-Directive means renewable non-fossil energy sources (wind, solar, geothermal, wave, tidal, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases). See Art. 2 a Res-Directive.
[283] See Jones (2004: 3.6).
[284] Article 11 (4) E-Directive. This right is limited to 15% of the overall primary energy of a Member State.
[285] See Merlin (2005: 161).
[286] See Glachant et al. (2006: 234); Scheepers et al. (2003: 22).
[287] The competitiveness of gas and coal is generally assessed by calculating the 'clean spark spread' and the 'clean dark spread'. The 'clean spark spread' represents the net revenue a generator makes from selling power, having bought gas and the required number of carbon allowances. The clean dark spread refers to an analogous indicator for coal fired generation of electricity. See http://en.wikipedia.org/wiki/Spark_spread.
[288] This is, for instance, the case in Germany, Denmark and Spain. See European Commission, COM (2005) 627.

Electricity consumption is affected by a number of different variables, such as the time of day, the temperature or the season and is never wholly predictable. As a result, supply does not always meet demand and there are periods during which electricity producers are in imbalance with respect to their contractual obligations. The various imbalances may cancel one another out, but generally the TSO will have to intervene and make adjustments in order to maintain the balance in the power system.[289] These actions inevitably give rise to costs and the question arises of who provides the supplementary electricity and who will pay the costs incurred.[290] The Directive states that balancing rules have to be objective, transparent and non-discriminatory, including rules for the charging of users of their networks for energy imbalance.[291] Moreover, terms and conditions for the provision of such services by the TSO, including rules and tariffs, must be published and adopted by the regulator pursuant to non-discriminatory and cost-reflective criteria.

Over time, many Member States have established balancing markets, which allow for a market-based procurement of balancing power and energy within single countries or control areas. The purpose of these markets is to contribute to the cost-efficient provision of balancing power.[292] As balancing markets are usually dominated by one or a few national suppliers, balancing energy generally reflects the energy mix of the incumbents, i.e. primarily large hydro and nuclear, coal and gas.[293] In certain cases, distributed generators, in particular large cogeneration units, also have access to the new balancing markets.[294]

The rules regarding the allocation of balancing costs vary widely among Member States.[295] Some have chosen to allocate costs exclusively to the generator that is out of balance, whereas others distribute them among all consumers. Most Member States have, however, decided to charge at least part of the costs to the generator in imbalance. The rules for the allocation of balancing costs are of particular importance for providers of intermittent renewable energy, such as wind energy. If Member States decide to allocate the full costs to the producers in imbalance, they may severely limit the penetration of these technologies. Improved weather forecasting, rules allowing intraday trading[296] as well as regional aggregation of intermittent power may, however, significantly reduce the need for balancing power and effectively contribute to lowering the bill.

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[289] See ERGEG (2006).
[290] See Jones (2004: 13.98).
[291] Article 11 (7) E-Directive.
[292] This situation has raised calls for consideration of cross-border integration of balancing markets. See ERGEG (2007: 4).
[293]See ERGEG (2007:4).
[294] See Degner et al. (2006: 18).
[295] ERGEG (2006: 7).
[296] Intra-day trading allows producers of renewables to trade electricity a few hours before delivery instead of one day ahead. This allows the producer of renewables to adapt its offer more effectively to its supply possibilities.

c) Energy losses and reserve capacity

Electricity transmitted through a network is always subject to losses.[297] Generally speaking, the further the electricity is transmitted, the greater the energy loss. The network operator can address this issue by requesting undertakings to deliver more electricity than they sell proportionate to their losses, or he or she can himself or herself add electricity to the network and charge for this service. Similar considerations affect reserve capacity.[298] A Member State may require all generators to keep a minimum level of reserve capacity available or entrust this task to the system operator, which will include the costs incurred to acquire electricity on the network tariffs. The Directive requires that if the transmission operator is responsible for either of these functions, he must acquire the electricity in a transparent, non-discriminatory and competitive manner.[299]

Due to the general tightening of generation capacity in a liberalised context, most Member States have taken measures to secure sufficient supply in periods of crisis.[300] Many countries have adopted some form of explicit capacity payments. Others have established support in the configuration of balancing markets or in the procurement of reserve capacity by the TSO. Finally, some Member States have used the possibility of tendering.[301] These rules, whose importance is likely to increase in a liberalised market, generally benefit flexible generation technologies such as large hydro and gas.[302]

6. The trading of electricity

The introduction of competition in the generation sector has significantly changed the way in which electricity is traded.[303] It is no longer considered an integrated product, which includes the 'transportation' service, but is traded separately, as a pure commodity at wholesale level.[304] The Directive leaves Member States free to decide how they want to organise the trading of electricity. This has led to the progressive emergence of regional submarkets, which share typical characteristics of zonal models, generally presented as 'hubs'.[305] In most Member States markets are organised around four different markets: a bilateral market known as an over-the-counter market (OTC), a

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[297] Jones (2004: 3.4).
[298] Reserve capacity is usually only used in the event of extraordinary levels of demand. See Jones (2004: 3.4).
[299] Article 11 (6) E-Directive; Article 14 (5) E-Directive.
[300] European Commission, COM (2004) 863.
[301] See for a discussion of the rules implemented by the Nordic electricity markets Amundsen et al. (2006).
[302] See for a thorough discussion on the various means for capacity payments Green (2005: 76); Patterson (2007: 61).
[303] Roggenkamp et al. (2005).
[304] See Roggenkamp et al. (2005).
[305] See Merlin (2005: 161).

power exchange (PX), a balancing market[306] and a mechanism for allocating interconnector capacity.[307] The bilateral market is most important in terms of volume.[308] Consumers tend to cover their basic consumption needs by OTC contracts and to use power exchanges for forward[309] and spot[310] contracts to adjust the long-term contracts to meet their actual needs. A real retail market has not yet emerged in any of the Member States. In practice many small consumers are still tied to their traditional suppliers and, if they have a choice, they are obliged to choose a supplier established in the same country.[311]

OTC markets favour bulk deals as transaction costs are largely fixed.[312] This represents a significant disadvantage for distributed generation, in particular of small renewables, which provide electricity of the order of a few kilowatts. This may be remedied, however, by aggregation rules, allowing small producers to gain access to the wholesale markets. Similar issues arise in connection with power exchanges. Mostly designed to meet the needs of large-scale generation, the production conditions of distributed generation and small-scale renewables are rarely sufficiently taken into account. By providing for long bidding times, they hinder, for instance, the efficient integration of small-scale technologies such as wind and photovoltaic.[313]

7. Research and development

The introduction of competition is deemed to foster innovation, as the process of dynamic adjustment to continual changes in consumer preferences provides incentives for producers to invest in R&D to remain competitive.[314] This virtuous cycle is, however, often slowed down due to the interest of private shareholders in looking for a quick return on their investments. In the electricity industry, the introduction of competition led initially to a decline of public and private research efforts and a greater focus of R&D on conventional technologies.[315] As a result, research fostering long-term innovations and the emergence of new technologies declined.[316] Moreover, the greater role of consumers

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306 The balancing mechanism is the responsibility of the TSO. Every hour, all participants inform the TSO of their physical transactions. This mechanism determines the price for any deviation measured between a participant's declaration and the real flows in the grid. See Boisselau (2004: 55).
307 The interconnector capacity market organises the allocation of interconnector capacity between the Member States. See Boisselau (2004: 53).
308 They can be physical contracts (for delivery) or financial contracts (hedging). All of them share three characteristics: a defined period, a certain amount of electricity, and a price. See Roggenkamp et al. (2005)
309 Delivery occurs in the future in forward contracts. See Roggenkamp et al. (2005).
310 Very short term, mainly day-ahead. See Roggenkamp et al. (2005).
311 See European Commission, COM (2007) 528.
312 Scheepers et al. (2004: 23).
313 Bidding times for the day ahead occur generally between 12 to 36 hours beforehand. See OPTRES (2007: 2, 152).
314 See Cameron (2007: 1.06).
315 Typically such research will be aimed at reducing the operating costs or increasing the reliability or efficiency of existing plants, rather than at developing new technologies, except for demand-side technologies. See Llamas (2000: 35).
316 See Llamas (2000: 35); Luther (2004).

in liberalised markets geared research efforts towards energy services. This tendency was partly offset by the support schemes introduced by certain Member States to enhance the deployment of renewable energy sources.[317] Also, the trend towards shorter payback times and improved supply-side efficiency fostered research in cogeneration and small-scale technologies.[318]

In the network business a major innovation emerged, the so-called 'Flexible Alternative Current Transmission System' or FACTS, that allowed network operators much more subtle control over flows of electricity through the many different circuits.[319] In general, however, innovation in generation technologies outstripped research relating to the network business.[320] If large-scale deployment of renewables is to become a reality in the next decade, research both in power generation and in network design will have to be stepped up considerably. This will probably not happen without significant government support.

8. Investment in new power generation

Under the past model of vertically integrated utilities enjoying a statutory monopoly, the plant mix was determined in a complex planning process.[321] Generally, a plan was first established to distinguish an optimum pattern of system development over many decades. In a second stage, economic studies for individual investment projects were undertaken to determine the optimal generation technology for the whole system. Frequently, the utility's decisions were influenced or revised by government action to take into account public policy goals such as the promotion of indigenous energy sources or environmental protection.[322]

This framework was effectively challenged by the first Electricity Directive and even more significantly by the second.[323] To open up investments in power generation to competition as much as possible, the dual approach pursued by the first Electricity Directive was abandoned and priority was granted to the sole authorisation procedure.[324] Only if interests in security of supply, environmental protection and the promotion of infant technologies require it can a tendering procedure be envisaged.[325] The latter may, however, only be adopted if the generating capacity being built or the measures being

[317] European Commission (2006b, 2007b).
[318] See Patterson (2007: 48).
[319] Patterson (2007: 104).
[320] See European Commission (2005).
[321] This so-called background plan included considerations relating to demand growth, capital costs, operating performance, economic lifetime, alternative types of generating capacity, and price forecast for the input fuel. See Pfaffenberger et al. (1999: 46).
[322] Pfaffenberger et al. (1999: 48)
[323] See Cameron (2007: 5.18).
[324] When granting a generation licence, Member States may relate, in particular, to the protection of the environment, energy efficiency and the nature of the primary sources.[324] With respect to small and/or distributed generation, Member States shall take into account their limited size and potential impact. See Article 6 (1) and (3) E-Directive.
[325] Article 7 E-Directive.

taken are not sufficient to achieve these objectives by means of the authorisation procedure.

In a liberalised environment, the framework for investment decisions changes radically.[326] Decisions concerning the construction of new power plants, in particular the timing and the technology mix, depend on the decisions of decentralised initiatives and no longer on public authorities.[327] Since utilities can no longer automatically pass on all their costs to customers, investment decisions are mainly based on profitability considerations.[328] To understand how investment decisions in power generation are made in a competitive environment, it is useful to consider briefly the main risks an investor has to consider when taking a decision.[329] These include, in particular, economy-wide factors such as the evolution of electricity prices, capital, transaction and fuel costs and conditions of network access, as well as the wider regulatory framework, including climate change regulation.[330]

a) Electricity prices, capital, transaction and fuel costs

The most fundamental change affecting the value of all investments in liberalised markets is probably the inherent uncertainty about electricity prices.[331] While this uncertainty affects all generation technologies, it does so in different ways. Uncertain electricity prices expose projects with a long lead and construction time to particular risks. As the long-term evolution of electricity prices can hardly be anticipated, there is a strong incentive to minimise sunk costs by entering the market with a lower initial investment and short pay-back times.[332] Accordingly, very large projects that must be built as a single large plant are considered more risky than projects that can be phased in as several smaller power plants in response to market conditions.[333] The fact that electricity prices are highly volatile also has an impact on the choice of technology. For instance, investors may plan to generate electricity only in periods of peak prices. This presupposes that the technology is highly flexible, easy to start up and shut off, and that capital costs can be recouped over a small number of hours.

A matter of expense which tends to increase in a liberalised context is the cost of capital. As investors are no longer guaranteed a fixed rate of return, the payment of higher interest rates is necessary to attract capital. In very general terms, the higher the level of risk faced by a particular technology, the higher the cost of its capital. This effect is reinforced in private undertakings, which are less likely to have access to low-cost financing and whose shareholders expect to reap short-term profits.

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[326] Levêque et al. (2007: 3).
[327] Levêque et al. (2007: 3)
[328] Pfaffenberger et al. (1999: 56).
[329] Pfaffenberger et al. (1999: 11).
[330] See also Fraser et al. (2003: 28).
[331] Fraser et al. (2003: 28).
[332] Discount rates are increasing and optimisation based on net present value will value short-term costs and benefits more than long-term impacts.
[333] Fraser et al. (2003: 29).

Another element to be considered when taking investment decisions is the cost related to transactions, i.e. the costs incurred when selling electricity and acquiring customers. This type of cost, which was almost nonexistent under the traditional framework, as the monopoly was granted an exclusive right over a category of 'captive' customers, plays a major role for new entrants, especially for small generators.

The significant variations of fuel costs are a significant risk factor for technologies where fuel costs represent a high proportion of total generating costs.[334] The key question for an investor in this type of plant is hence the level and development of the difference between the price of electricity and the cost of the fuel used to produce it, the so-called 'spark spread'.[335]

Significant construction times and long operational lives of nuclear, large hydro, offshore wind and coal-fired plants imply that assumptions on risks as varied as the evolution of electricity prices, 'overnight' construction,[336] capital and fuel costs must be made for the next 40–60 years. In a market, investments with a payback time of over ten years are considered as very risky as they exceed the time horizon which is generally deemed acceptable by those who finance a project.[337] As a result, capital costs of coal and even more for nuclear and hydro plants are generally many points higher than those for investments in gas, which have a much shorter payback time.[338] In comparison, the quicker payback time and the possibility of distributed generation and small-scale co-generation being installed rapidly are clear advantages in a competitive market.[339] New small-scale renewable energies are, however, penalised by the fact that upfront costs are important and largely untested technologies carry a high risk premium.

With respect to the energy price uncertainty, renewable energies, with the exception of biomass, fare best, as their inputs are often free of charge. Among the fuel-based technologies, nuclear is the least exposed to this problem, as a modest amount of uranium can keep a reactor running for decades. The risk of an escalation of prices is probably the most prominent for gas, as prices are largely indexed to oil prices and resources concentrated in politically unstable regions like Iran and Russia.[340] The price of coal is, in comparison, relatively stable due to the large number of mines and a reasonably fluid market. Biomass reserves are potentially large, but its increased use for various energy-production purposes may put significant pressure on prices in the future.

Overall, the variability of electricity prices, the use of market-based procurement of balancing and reserve energy leads to increasing valuation of flexible technologies by the

[334] Fraser et al. (2003: 29).
[335] Fraser et al. (2003: 30).
[336] 'Overnight' cost is the hypothetical cost of a generating plant if it could be built instantly ('overnight'). The figure does not reflect inflation, the costs of construction financing, or the length of time that it takes to build the plant and associated cash flows. See Joskow (2006: 12).
[337] Rogeaux (2006 : 301).
[338] A study by the Chicago University in 2004 estimated the cost of capital for nuclear power generation with 12.5 and the cost of capital for coal and gas-fuelled generation with 9.5. See Rogeaux (2006: 301).
[339] See Patterson (2007: 56)
[340] In the UK, wholesale gas prices quadrupled between 2004 and 2006. See Pollitt (2007: 7).

market.[341] This trend favours, in particular, power based on gas generators in all sizes. Among the large-scale generators, large hydro is clearly the technology best suited to respond to rapid changes in demand and production. Nuclear power is penalised as nuclear power plants take a long time to be started up and shut off. So is co-generation, which follows heat demand, and renewable energies of intermittent character, which only produce electricity when the wind blows, the water runs or the sun shines.

b) Network access tariffs

The conditions of network access as well as the level and the allocation of network tariffs are important aspects to be considered when investing in power generation. Only if the investor is certain that the electricity produced will be taken up by the grid in equitable conditions will he or she be willing to risk his or her money. To grant non-discriminatory access to the grid, the second Electricity Directive significantly enhanced unbundling requirements and generalised regulated TPA.[342] Notwithstanding these improvements, access to the grid is hampered by vertically integrated network operators.

With regard to network tariffs two main components are generally distinguished: the charge requested for connecting the generator to the network ('connection tariffs') and the fee paid for its usage, i.e. the transport of electricity and the ancillary services provided by the TSOs and DSOs ('use-of-network tariffs'). For cross-border trade in electricity, a third charge is levied if capacity is scarce.[343] Both connection and use-of-network tariffs are subject to the principle of non-discrimination.[344] According to this principle, tariffs have to be applied to all users of the network without the possibility of individual renegotiation, discount or exemption. The principle of non-discrimination does not, however, imply that a uniform tariff has to be set.[345] Different circumstances may be taken into account, such as the differences in costs the users impose on the grid or differences in quantity or time.[346]

(1) Connection tariffs

With the exception of large wind offshore technology, which demands the construction of large underground lines, connection tariffs are generally a minor cost factor for large utilities, as reinforcement costs related to the transmission network are in general shared by all users of the network. This is different for distributed generation, where connection charges are generally borne by the generator and represent a significant cost factor.

[341] See Rogeaux (2006: 297). This trend will be further enhanced as large quantities of renewables with intermittent character will have to be integrated into the electricity market in accordance with the 'climate package'. See European Commission, COM (2008) 19.
[342] Article 20 E-Directive.
[343] See for the guidelines on the management and allocation of available transfer capacity of interconnections between national systems the Annex of the Cross-Border-Regulation.
[344] See Article 23 (2) E-Directive.
[345] See Jones (2004: 3.15).
[346] Lévêque stresses that the legal non-discrimination principle contradicts the economic principle of efficiency. If the network operator is allowed to charge a different price to each consumer, more precisely, the maximum price each consumer is willing to pay, its profit is optimised. See Lévêque (2003: 16).

Connection charges usually include not only the expenses related to the connection of the generator to the nearest point in the distribution network but also those that accrue in relation to grid reinforcements.[347] To mitigate somewhat the full impact of their allocation to small producers, the Electricity Directive requests regulatory authorities to take full account of both costs and benefits of these technologies.[348] This means that in fixing connection charges the regulator should also take into consideration the benefits provided by distributed generators, which may take the form of enhanced system reliability, avoided transmission and distribution line losses and costs, congestion relief and avoided infrastructure investments.[349]

With respect to renewables,[350] Member States may, if they judge it appropriate, require the network operator to bear all grid-connected costs.[351] This mode of allocation is, in principle, more favourable to small renewables. It may, however, in the long run have a deterrent effect on the willingness of DSOs to integrate distributed generation. As the DSOs revenue decreases due to increased charges, he or she may be tempted to hinder their deployment.[352]

Finally, Member States have to adopt rules allowing a fair allocation of grid-connected costs among all producers of renewables benefiting from them.[353] This implies that regulators must avoid that the first producer to be connected to the grid has to bear all the costs, whereas later producers benefit from the infrastructure without paying for it.

(2) Use-of-network tariffs

Use-of-network tariffs vary widely, not only in terms of services covered and features, but also regarding their mode of allocation.[354] Usually, services are defined broadly and include infrastructure costs and operation and management costs, as well as costs relating to energy losses, ancillary services (reserve and reactive energy) and congestion. Balancing fees are usually recovered separately. The most frequent network tariffs contain differentiations relative to energy and/or capacity,[355] location and time. With regard to allocation, some Member States have chosen to charge them exclusively to

[347] The network tariffs, which include exclusively the costs related to the connection of the generator to the nearest point in the distribution network, are commonly called ‘shallow fees’, whereas the network fees including also the network reinforcement costs are called ‘deep fees’. See Degner et al. (2006: 19).
[348] Article 23 f E- Directive.
[349] See Ofgem (2007); Pepermans et al. (2005); Degner et al. (2006: 18); Connor et al. (2004); IEA (2002); Scheepers et al. (2004); Timpe et al. (2004); Dunn (2000); Takahashi et al. (2005); Mitchell (2000); Raineri et al. (2005); Donkelaar et al. (2005).
[350] The ‘renewables’ refers to all non-fossil renewable energy sources as they are defined by Article 2 a Res-Directive.
[351] Article 7 (2) Res-Directive.
[352] See Degner et al. (2006: 19).
[353] Article 7 (2) Res-Directive.
[354] For certain categories of users they vary up to a factor 10 between the different Member States. See Glachant (2005: 206).
[355] The tariff may be partly calculated on the basis of the energy actually injected or withdrawn and partly on the capacity for injection and withdrawal. See Glachant (2005: 208).

consumers, others only to generators. Most frequently, they are, however, split between these two categories.

Given that a substantial part of the cost of a unit of electricity is the charge for the network, the manner in which network tariffs are calculated and allocated – both the grid-connection and use-of-network fees – is of crucial importance for the competitiveness of electricity generators, especially for small producers of renewables and co-generation.[356] As a matter of fact, it is only within the framework set by network tariffs that electricity generation is subject to market forces.

Notwithstanding the principle of non-discrimination and the prohibition on applying distance-related transmission tariffs laid down by Community law, national regulators remain essentially free to fix the level and the mode of allocation of network tariffs. So far, they have shown little motivation to modify the incentives of traditional network regulation and thus continue to severely limit the opportunities for small-scale generation.[357] The pressure for a fundamental change is however increasing.[358] One option attracting increasing attention is the construction of direct lines that can link local generation with local loads. This possibility, which does not exclude the concomitant use of the regulated network,[359] effectively undermines the network monopoly and is likely to re-shape the structure of future networks.

c) Climate change regulation

A fairly new challenge for utilities is the uncertainty related to the price of carbon due to climate change regulation.[360] With the launch of the ETS, the unknown future value of carbon has become a critical factor for power generation investment.[361] Another crucial question is whether the carbon price may be passed on to the customers. If this is the case, then carbon price uncertainty poses no particular risk as revenues could change by exactly the same amount as costs. Economic theory suggests that if carbon cost is treated as an opportunity cost, then it will always be factored in to the electricity price, given the low elasticity of demand. Several factors, however, may influence the extent to which the price is passed on, in particular the way emission allowances are allocated.[362] These uncertainties have a deterrent effect on investments as utilities tend to delay plant closure and replacements to allow them time to gain more information so as to make better investment choices in the future.

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[356] See Patterson (2007: 57).
[357] See Patterson (2007: 58).
[358] In the United Kingdom a working group has been set up to study how the charging methodologies of distributed networks would have to be modified to include many small distributed generators. See at: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/Pages/Policy.aspx
[359] See in particular Article 22 (3) E-Directive, which stipulates that the possibility of supplying electricity through a direct line shall not affect the possibility of getting electricity from the regulated network.
[360] Blyth (2006: 39).
[361] See Neuhoff (2007).
[362] See Sijm et al. (2006).

The uncertainty related to the future price of carbon is probably the most significant risk for investments in coal and to a somewhat lesser extent for investments in gas power. As neither the international climate framework for the period after 2012 nor the criteria for the allocation of greenhouse gas permits in the third period of the ETS running from 2012 to 2020 have yet been defined,[363] the price of carbon for the next 12 years is difficult to anticipate. Moreover, as coal power plants have a lifetime of many decades,[364] the risk related to climate change regulation is essentially unpredictable. Nonetheless, experience gained in the first two allocation periods of the ETS shows that governments are reluctant to impose tough environmental standards which could jeopardise the long-term viability of the main players in the power industry.[365] Furthermore, power plants may hedge the carbon risk to a certain extent by the construction of 'capture-ready' plants, which facilitate retrofitting facilities with CO_2 capture in the future.[366]

9. The modified institutional and regulatory setting

The introduction of competition has not only radically changed the way utilities are managed, it also means a sea-change for the state, its competences and role vis-à-vis the industry and the consumers.[367] Whereas the traditional system allowed the state to adopt an integrated approach with respect to economic and other public policy goals, this has become more difficult in a liberalised context. Economic and non-economic goals are increasingly pursued by different public entities.

The shift of competences is probably most significant in the field of economic regulation. While the government was previously closely involved in the planning of new production and grid development, its principal role in a liberalised context is to guarantee a level playing field. As agencies entrusted with the enforcement of antitrust law[368] have in most cases proved inadequate to implement the new market rules, governments have usually set up a separate regulatory authority with a certain degree of independence, to guarantee an arms-length approach in regulatory decisions.[369] The 'second' Electricity Directive generalised this institutional innovation by requesting all Member States to establish an

[363] See European Commission (2008) 16.
[364] This date corresponds to the actual time horizon of the third ETS period and international climate negotiations.
[365] See de Sépibus (2007a and b).
[366] This means that they ensure that all known factors that would prevent installation and operation of the capture of CO_2 in the future have been eliminated. This might include a study of options for CO_2 capture retrofit and potential pre-investments, the inclusion of sufficient space and access for the additional plant that would be required and the identification of a reasonable route to storage of CO_2. See IEA (2007: 3).
[367] Fowlie (1999: 48).
[368] The main goal of antitrust law is to control the exercise of market power of firms to ensure overall efficiency. Its mainly ex-post remedies are designed to correct certain behaviours of existing undertakings, but are insufficient to create a market dominated by a single monopoly. See de Streel (2006).
[369] The regulator has to be independent from the interests of the industry to ensure its impartiality. If the former monopolist remains the property of the state, special care has to be taken to ensure that the government does not interfere in the decisions of the regulator to favour its own undertaking. See COM (2007) 528.

NRA charged with supervising the electricity sector.[370] The new body has to be endowed with a minimum set of powers and to be independent from the interests of the electricity industry. The Directive requires the NRAs to coordinate their activities with one another as well as with the competition bodies and to liaise with the Commission.[371] In each Member State there now exists a 'holy trinity' of public bodies responsible for ensuring the efficient functioning of the market, comprising the lead ministry, the sectoral regulatory agency and the competition authority.[372]

If the designation of an independent regulatory authority was a regular pattern of institutional reform in response to the new functions of the state as a market regulator,[373] less attention was paid to the consequences of this process for the capacity of the state to effectively pursue other public policy goals.[374] For the government, liberalisation meant that it could no longer pursue environmental objectives by taking an active role in defining the plant mix, by influencing electricity prices and by regulating demand.[375] These traditional approaches had become inadequate and obsolete. Moreover, the changed incentive structure of the industry rendered the adoption of standards as well as economic instruments difficult, as utilities put up strong resistance to regulatory changes likely to affect their competitiveness. Finally, to the extent that governments imposed public service obligations on certain utilities, care had to be taken that these measures did not tilt the level playing field. More generally, the pursuit of environmental objectives with financial implications for the state became more difficult as the costs of meeting public policy objectives were transferred from generation accounts to public accounts.[376]

Certain governments responded to these challenges by requesting the newly created regulatory authorities to integrate environmental aspects when enforcing market rules.[377] The act of balancing economic and environmental goals is, however, a complex exercise requiring good knowledge of the environmental consequences of economic regulation. As such skills do not usually form part of the core competence of economic regulators, they often considered this task to be the responsibility of the government.[378] The latter, however, often lacked familiarity with the intricacies of economic regulation. Consequently, nobody was fully assuming the responsibility for the issue and much was slipping through the cracks.

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[370] Article 23 E-Directive.
[371] Cameron (2007: 3.06).
[372] Cameron (2007: 3.07).
[373] See Genoud et al. (2002).
[374] See in particular Isidoro (2006).
[375] An example of this kind of intervention is provided by a law passed in the US in the 1980s, which obliged utilities to provide for so-called 'integrated resource planning'. Under this law utilities had to prove to regulators that, in planning to meet future electricity demand, they had considered all possible supply alternatives – including demand-side management programmes, whereby future demand was 'met' by reducing demand through programmes improving energy efficiency. See Fowlie (1999: 55).
[376] Whereas under the traditional regime fixed prices guaranteed that utilities had sufficient revenues at their disposal to pursue *inter alia* environmental goals, this is no longer the case in a competitive environment.
[377] See in particular the role of Ofgem in the UK at:
http://www.ofgem.gov.uk/Sustainability/Pages/Sustain.aspx
[378] See Fowlie (1999: 48).

Whereas the first Electricity Directive merely stated that Member States were allowed to pursue environmental protection as a public service obligation, the second Directive makes more allowance for the changed institutional and regulatory setting. This is in particular displayed by Article 3, which requires Member States to ensure that electricity undertakings are operated 'with a view to achieving a competitive, secure and environmentally sustainable market in electricity'. This Directive explicitly mentions climate change as a legitimate public service obligation. Moreover, Member States are not only allowed to pursue goals of environmental protection, but are requested to implement appropriate measures to attain this objective.

The possibility of derogating from certain provisions of the Directive is, however, not a 'carte blanche' for Member States, as is recalled by Article 3 (2) E-Directive. The relevant provisions of the EC Treaty, in particular Article 86 EC, which refers to the rules on competition and state aid, remain applicable.[379] Moreover, Member States have to inform the Commission of all measures adopted to fulfil public service obligations and their possible effect on national and international competition, whether or not such measures require derogation from the Directive.[380]

Overall, the provisions on public service obligations are somewhat confusing, reflecting the delicate balance the legislator has attempted to strike between the necessity for tackling climate change and the familiar concern about distortions of competition. The greater leeway granted to Member States is in some way counterbalanced by more onerous informational requirements, which enable the Commission to intervene in the case of unnecessary market distortions. An interesting clause in this regard is the provision requesting the Commission to monitor the environmental consequences of liberalisation.[381] Indeed, only if the Commission is sufficiently informed will it be able to take a fair decision in potential cases of state aid.[382]

C. Recent trends in the European power industry

In its fledgling stages liberalisation greatly favoured gas power as the primary fuel for new generation.[383] This trend was supported by relatively low gas prices, the development of the highly efficient CCGT technology, environmental legislation, such as

[379] See in particular on the interpretation of Article 86 EC, ECJ, Case C-280/00, Altmark Trans GmbH v Regierungspräsidium Magdeburg, 24.7.2003. Indeed, the 'Altmark' judgment sets out that the measure must however satisfy four conditions according to which (i) the Member State must have imposed clear public service obligations, (ii) the parameters for the calculation of the compensation must have been determined in advance, (iii) the compensation must not exceed the necessary costs, yet may include a reasonable profit, and finally (iv) either must not exceed the costs of a typical undertaking, well run and adequately supplied with the means of providing the service or the provider must have been chosen by way of a public procurement procedure.

[380] Article 3 (9) E-Directive.

[381] Art. 29 (b) E-Directive.

[382] See Article 87 EC Treaty.

[383] Gas power rose by a factor of 2.5 in the EU-15 between 1990 and 2004. See EEA (2007b).

the Large Combustion Plant Directive,[384] as well as the reduction of subsidies for coal in certain countries.[385] The newly liberalised context also proved favourable to the operation of large hydro, which could reap significant benefits by providing peak energy.[386] Nuclear power, generally, also fared well thanks to relatively low operational costs.[387] The share of coal and lignite, on the other hand, declined, but has risen again in recent years.[388] Overall, the efficiency of thermal power plants increased due to re-powering, reduction of outages and better maintenance.[389] In recent years, however, a marginal decline in efficiency has been observed primarily due to an increase in the price of gas with respect to coal.[390]

The market share of new renewables increased only marginally.[391] With the new millennium this trend was reversed, principally due to the steep increase of on-shore wind energy in Denmark, Spain and Germany.[392] The impressive progress of wind energy and later also of solar energy[393] occurred thanks to the adoption of feed-in-tariffs, which

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384 The Large Combustion Plant Directive required Member States to invest in pollution abatement technologies to lower emissions of air pollutants. See Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 O.J. L 309, p. 1–21 on the limitation of emissions of certain pollutants into the air from large combustion plants.

385 For instance, the UK has cut the support for expensive untried clean coal technologies. See Pollitt (2007: 4).

386 The share of hydro is, however, very variable from year to year due to changing weather patterns. See EEA (2007c); Glachant (2006).

387 Electricity produced from nuclear fuels continued to grow in absolute terms from the 1990s to 2004 in the EU-15, although its share of total production fell slightly to 31% in 2004. See EEA (2007b); Glachant (2006). The relatively low operating costs of nuclear power plants induced a large number of the nuclear plants now operating in the US to apply for extensions on their operating permits that allow them to continue operating for an additional 20 years. See Joskow (2006: 1).

388 The share of coal and lignite declined from 37.4% in 1990 to 29.5% in 2004. The share of oil is also slowly diminishing as many of the existing oil-fired plants are kept only as part of the required power reserve margin. See EEA (2007b).

389 The average energy efficiency of conventional thermal electricity production in the EU-15 improved over the period from 1990 to 2004 by 3.2 percentage points to 38.2%. The growth in the use of combined cycle gas turbine plants (CCGT) has been an important factor in the improving efficiency seen in the pre-2004 EU-15 Member States. However, continued improvements have also been made in conventional coal generation. See EEA (2007a).

390 See EEA (2007a).

391 Renewable energy's share has only grown slightly since 1990 (12.2%) to 13.7% despite increasing substantially in absolute terms. Total renewable electricity production grew by 49% over the period from 1990 to 2004, but this was only a little faster than the growth in electricity consumption itself (a 34% increase over the same period). See EEA (2007d: 1).

392 In 2006 wind energy covered 19%, 8% and 5%, of electricity needs in Denmark, Spain and Germany, respectively. At present however, output still accounts for a small (around 0.3%) proportion of total energy consumption and 5% of renewable energy consumption. See EEA (2007c): European Commission (2004: 19).

393 Between 1990 and 2004 in the EU-15, solar energy grew by around a factor of five. Solar thermal energy developments in Austria, Germany and Greece benefited greatly from proactive government policy coupled with subsidy schemes and communication strategies that emphasised the benefits of solar thermal energy. In 2006, Spain passed a law making solar panels compulsory in new and renovated buildings. In most Member States, solar energy comes from solar thermal energy, rather than electricity generated using photovoltaic (PV) cells. The proportion of solar energy in total renewable energy amounted to 0.7% (only 0.04% of total energy consumption) in 2004. See EEA (2007c).

guaranteed investors a stable return on investment.[394] However, overall, the share of new renewables remains small.[395] Gas power continues to be installed, but more slowly. Its linkage to oil prices, increasing concerns over security of supply and the still highly concentrated gas market contribute to making it less attractive, especially for cogeneration.[396]

Electricity consumption grew across the EU at an average annual rate of 1.8% between 1990 and 2004.[397] This rate of increase was highly correlated with the average rate of growth in GDP over the same period. The increases in electricity consumption, however, resulted not only from a growing economy, but also from an increasing share of electricity in final energy consumption, rising from 17.4% in 1990 to 20.0% in 2004. The attractiveness of electricity was, in particular, influenced by a decrease in electricity prices between 1990 and 2006.[398] Growth in electricity consumption was particularly strong in the service sector, followed by households.[399] Although improvements in the efficiency of large electrical appliances led to significant decreases in average consumption by these items, these decreases were largely offset by increases in the use, numbers and size of large and small appliances. A further increase in electricity consumption comes from appliances kept in 'stand-by mode', which are estimated to amount to approximately 5–10% of EU household energy consumption.

Emissions of CO_2 from public electricity and heat production have increased by 6% in the EU-15 since 1990, driven by increasing electricity production in thermal power plants[400] and thus largely offsetting an emission reduction of about 8% in the 1990s.[401] After a steady increase between 1999 and 2003, CO_2 emissions decreased slightly for the second consecutive year in 2005 due in particular to an increase in the share of renewable energy sources.[402]

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[394] Between 1990 and 2004, wind energy in the EU-15 grew by a factor of 75; and increased by 32% between 2003 and 2004. See EEA (2007c); OPTRES (2007: 1); Sawin (2004). According to EWEA, wind energy represented 32% of all electricity installed in the EU between 2001 and 2006. See EWEA (2006: 6).

[395] The share of new renewables has been augmented by only 1.4% since 1990. See EEA (2007b: 3).

[396] The share of electricity produced from combined heat and power (CHP) in the EU-15 remained almost constant between 2000 and 2004 at 9.5%. Strong policy support to promote the technology in many Member States was counteracted by the effect of increasing gas prices and relatively low electricity prices, which reduced the competitiveness of gas-fired CHP-plants. See EEA (2007e).

[397] This makes an overall increase of 22.6%. See EEA (2007f).

[398] Overall, prices for electricity for households in the EU-15 fell by 12% between 1990 and 2006, primarily as a consequence of market liberalisation. Oil and gas price increases and the effect of the EU emissions trading scheme have started to push prices up again, with a 5% rise in the EU-25 between 2005 and 2006. By comparison, in many of the new EU-10 Member States household electricity prices rose substantially as price controls and subsidies were removed. See EEA (2007f).

[399] In the industry sector, electricity consumption increased, but at a slower rate than that of the services and household sectors. See EEA (2007f).

[400] Electricity and heat production in the EU-15 increased by about 38% between 1990 and 2005. See (2007d).

[401] The reductions in the 1990s were the result of increasing efficiency of power plants, economic restructuring in the new federal states in Germany and changes in the choice of fuel in the UK after the latter had liberalised its electricity market. See EEA (2007d: 25).

[402] See EEA (2006 : 18); EEA (2007d: 66).

Conclusions

The European process of liberalisation has radically transformed the regulatory environment of the power industry. It is still unfinished business, as the ongoing revisions and the uneven implementation of the Electricity Directive testify. Its long-term impact on trends in greenhouse gas emission cannot yet be fully ascertained as the largest part of European power plants is only to be replaced in the next two decades. Also, current emission trends do not reflect primarily the impact of liberalisation but are to a large extent the result of investments made under the monopoly regime and are influenced by the measures taken by the European Union to combat climate change. Nevertheless an attempt to draw some conclusions on the principal insights gained so far may still be worthwhile.

With a share of approximately 1/4 of the greenhouse gas emissions of the European Union, stemming mainly from the combustion of fossil fuels, the European power industry will have to make a significant contribution if it wants to reduce its climate footprint. A reduction of its CO_2 emissions, the main greenhouse gas emitted by the power sector, may be attained by a combination of measures, such as the increase of supply-side and end-use efficiency, a switch from coal to gas, the equipment of fuel power plants with CCS and/or by a more general substitution of fossil fuel power plants by generators using renewable energy sources and nuclear power.

The impact of the European liberalisation process on current CO_2 emissions is ambiguous. Reduced to its core concept, liberalisation aims to free the electricity production from the constraints of public control by permitting it to be sold largely as a commodity.[403] As such, it promotes an electricity system that drives economic actors to focus on selling more kWhs rather than providing more services with fewer kWhs. Moreover, the continual pressure on all producers to keep down prices, for fear of losing market shares, promotes the production of the cheapest unit of electricity. These trends clearly contribute to making end-use energy efficiency measures less attractive. On the other hand liberalisation gives costumers a greater choice and enables them to select the type of generation technology not only based on costs but also on environmental performance. It generally also improves supply-side efficiency through the constant pressure to reduce costs.

By establishing as a general rule the principle of 'economic precedence' for the dispatch of electricity, the new operational rules usually favour large-scale generation such as large hydro and nuclear,[404] followed by coal or gas. The competitiveness of coal in comparison to gas varies according to the evolution of fuel prices and the price of the greenhouse gas allowances of the ETS.[405] Whereas gas was very competitive in the

[403] See Byrne (2003).
[404] Both technologies have low operational costs and are hence very competitive in the current electricity market.
[405] As a rule, a high carbon price favours use of gas whereas a low carbon price promotes coal. Since the steep rise in gas prices, coal has generally become more competitive than gas. In the UK though, the merit

fledgling stages of liberalisation, the recent increase of gas prices and the high concentration of the gas market have made this technology less attractive despite the high efficiency of the CCGT technology. Small and middle-sized cogeneration mainly fuelled by gas also suffered from the negative evolution of the gas price. Offshore-wind and most small-scale renewables, with the exception of biomass and wind in certain locations, are not yet competitive without governmental support.

By limiting the tendering procedure to exceptional circumstances, the second Electricity Directive has set the legal framework for extensive competition in the generation sector. As a result, investment risks in power generation have been shifted from captive consumers to investors. This has generally made large-scale generation with long pay-back times, significant fuel price uncertainties and high capital costs more risky.

Thanks to its flexibility and relatively short lead time gas power became the fuel of choice for investors in the 90s. In recent years, the steep increase of gas prices, combined with concerns over security of supply, has, however, triggered a host of coal power projects, which suggests that the 'dash for gas' of the 1990s is about to be replaced by a 'dash for coal'.[406] While coal power plants are increasingly 'cleaner' due to higher efficiencies, the equipment of power plants with CCS, which is the only technology that allows a radical reduction of the CO_2 emissions of fossil fuel plants, will not be adopted in a liberalised market in the absence of mandatory requirements or clear signs that carbon prices increase significantly in the future. As CCS has yet to be tested in large demonstration plants, its future deployment will largely depend on the success of the new climate 'package',[407] the inclusion of CCS projects by the Clean Development Mechanism[408] and initiatives taken by countries with a high share of coal power such as the US.[409]

Despite their current competitiveness, the shares of large hydro and nuclear in the European energy mix are likely to decline in the future due to a scarcity of adequate sites for large hydro and the uncertainty over the replacement of aging nuclear plants in a liberalised context.[410] The prospects for nuclear power may, however, increase in a

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order has changed recently due, in particular, to higher coal prices. See Argus Gas Connections – EU, 8 February 2008, p. 10.

[406] E3G (2008: 1).

[407] See in particular European Commission, COM (2008) 13, COM (2008) 18. It remains highly uncertain whether the plan of the Commission to have 12 demonstrations plants built by 2015 in the EU will become reality. If Member States and investors do not show more willingness to significantly support this technology as they currently do, the wide-scale deployment of this technology at the start of the 20s is jeopardised.

[408] The CDM does so far not allow the emission of credits for CCS projects. If this is modified in the future, CCS projects may be co-financed by greenhouse gas credits obtained in the framework of this flexible mechanism of the Kyoto Protocol.

[409] Although the US has not ratified the Kyoto Protocol, the current political context suggests that under the new President this country may take significant measures for the mitigation of climate change. As it has huge coal reserves at its disposal, it is expected that it will contribute to the development of CCS.

[410] A general decline of nuclear power stations in the EU is most likely, as few new nuclear plants have been commissioned in recent years to replace those reaching the end of their lives. See EEA (2007b); EEA (2007c); Zaleski et al. (2003).

context of higher carbon and fossil fuel prices.[411] Most probably, however, a so-called nuclear 'renaissance' will not take place without the decisive support of certain Member States.[412]

The impact of liberalisation on the development of small-scale renewables and offshore wind is mixed. Whereas the introduction of competition, the principle of non-discrimination and the unbundling requirements as well as the possibility of building direct lines contribute to fostering its deployment, other trends induced by liberalisation, such as the pressure on production costs, the reduction of R&D budgets, the increase of capital and transaction costs have a negative impact. Moreover, important market barriers persist due, in particular, to the lack of effective competition, high market concentration of incumbents, insufficient unbundling requirements, low interconnection capacity, the difficulties in gaining access to wholesale markets, and operational rules biased in favour of large-scale generation. Finally, and possibly most importantly, the existing framework has not yet facilitated a swift modernisation of both distribution and transmission networks, which would allow a multitude of small generation sources to be connected easily and at accessible prices to the grid.[413]

These barriers suggest that no breakthrough for renewables will occur in a liberalised market without a careful overhaul of the current design of the legislative and institutional framework. To a certain extent, their penetration will, however, also be influenced by the evaluation of the price risk of fossil fuel generation. As Awerbuch demonstrates convincingly, the traditional 'discount rates'[414] applied for energy projects generally do not take the risk of an escalation of fossil fuel prices sufficiently into account. If investors in fossil fuelled plants were to take this risk seriously, fossil-fuel power would indeed become much more expensive and thus enhance the competitiveness of renewables.[415]

In any attempt to reform the system, special focus should be placed on the incentives provided by network tariffs to network operators. Only if the technical know-how of these key actors can be harnessed to develop and deploy new 'smart' devices, while guaranteeing all market players fair access to the grid, will a smooth transition of the current system dominated by large-scale generation to a more 'mixed' system, allowing the simultaneous deployment of both large- and small-scale generation, be possible. Such changes will not come about overnight and they will not occur spontaneously in a liberalised market. They will have to be continuously sustained by strong regulators and

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[411] The economic justification for the construction of new nuclear plants is controversial, as the studies of the MIT and the IEA demonstrate. Joskow shows convincingly that the conditions that led to the construction of the nuclear reactor in Finland, which is based on long-term contractual arrangements that the owner has with large buyers of power, are not easily replicable. See Joskow (2007: 7).
[412] CEOs of large power corporations are reluctant to invest in new nuclear power stations, as any major incident in relation with this technology might have a devastating impact on the construction of new nuclear reactors.
[413] See for instance the concept of 'plug and play' pioneered in the US. This concept pursues the goal of connecting generators to the network so long as the proposed device meets the requisite safety and other standards. See Patterson (2007:106).
[414] These are nominal interest rates that allow today's money to be compared with future money. See Awerbuch et al. (2003).
[415] Blyth et al. (2007); Rickerson et al. (2005).

institutions under democratic control, committed to bring about a progressive decarbonisation of the industry and using market forces to trigger innovation.[416]

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416 Patterson suggests that the regulator should be given a more creative role. For this to happen, it must have the requisite authority and backing from the relevant government. This in turn means that the government must understand the true range of technical, financial and institutional options and choices available to electricity policy. See Patterson (2007: 110).

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