

## *Nuclear and Generation Technology Mix in Competitive Electricity Markets*

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Competitive electricity reforms began to emerge at the beginning of the 1990s. We now have a certain distance, especially in Europe and the United States, for observing behaviour in terms of investments in generation within a competitive framework. The oldest of these reforms currently have 15 years of experience, as in England (in effect since 1990) and Norway (since 1991). The first European Directive on creating a single electricity market<sup>2</sup> was adopted a decade ago and enacted as of 1997 (like in Spain) and 1999 (like in Italy). In the United States, the beginning of the competitive reforms can be traced to the creation of Independent System Operators (ISOs) between 1995 and 1997 covering Texas, California, and PJM (Pennsylvania, New-Jersey and Maryland), but a true opening of competitive wholesale markets cannot be said to antedate 1998.

Did these competitive reforms of the electricity industry have an impact on the choice of generating technologies? Do the new competitive pressures create an incentive for producers to select new methods for generating electricity (like the *Combined Cycle Gas Turbine*; hereafter, CCGT) and to abandon old technologies adopted under their previous status as utility monopolies, these former technologies favoured by policies and government subsidies and financed by a guaranteed sales price? Would there be a new trend that the most capital intensive technologies (e.g., nuclear power) would be avoided? What link can we trace from actual competitive market reform to actual generation technology choice?

Letting apart the economic theory of capacity investment and its cycles, and its actual patterns in liberalised markets [see Green 2006], there is room for a more empirical study of actual generation technology choice. We will address the potential impact of the competitive reforms on the choice of production technology in three stages<sup>3</sup>. In the first stage, I will

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<sup>2</sup> *Common Rules for the Internal Market in Electricity*, Directive 96/92/EC of the European Parliament and the Council of December, 19<sup>th</sup> 1996.

<sup>3</sup> I will let apart the particular cases of peak-load technologies and renewable energy. As we have seen yet, electricity generation is characterized by the coexistence of several technologies responding to different parts of

examine whether the main competitive reforms in the United States and Europe fostered an evolution in the volume and technology of investments in generation. If a technology change occurs with low volumes of investment we could doubt about its significance. Therefore we have to establish if these reforms were indeed often accompanied by high levels of investment, and if a technological change particularly favoured new gas-based CCGT technology.

Having verified both the importance of the investment wave and of the technological shift, we have to ask, in a second stage, why this technology change occurred in that wave of capacity investment. By looking at the traditional method of comparing electricity generation costs, which is called “*levelised cost methodology*”, we will find that it provides a simple economic explanation for this technological rift by establishing the CCGT system as the least expensive among existing technological alternatives. However, in contrast to cost analysis performed in the UK and the US, the main French analysis of the cost of electricity generation always find in favour of nuclear. Then, we will dedicate a third and final stage to understand why cost analysis can diverge that much. We will particularly focus on the economic determinants that have been accounted for in the comparative analysis of technology costs under a competitive framework, taking as a benchmark the cost study made at the MIT in 2003. As already suggested by [Green 2006], we will see that the core of this debate on the actual costs of new plants is on evaluating the effects of competitive power markets and of vertical disintegration of generation on the cost of capital. Since nuclear is extremely capital intensive, two to three times more than its alternative technologies, it is much more sensitive to the way the financial market and the banking industry actually take into account the risks and uncertainty of generation investment.

### ***1 One decade of investment in generation in a competitive framework***

Naturally, the multitude of U.S. and European experiences in competitive electricity reforms is characterised by a vast range of timings and a broad diversity of modalities. These reforms do not all present the same investment profiles or technological choices. However, two broad traits can be seen to prevail. On the one hand, when these reforms were

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the load; notably a specific technology can be used to generate at peak (like a gas turbine having no “combined cycle” to recycling the heat produced by the ignition of the fuel). Renewable energy is another particularity in technology choice, since the growth of renewable technologies’ adoption still depends from the subsidization by public energy policy and is not driven by independent decisions taken by the electrical companies.

accompanied by investments in generation, very large volumes of new capacity were created (up to + 30 or + 40 %). This simple fact means that it has been a wave of investment of a particular significance. On the other hand, the technology principally used in this important wave of “competitive” investments is relatively new: gas-based systems (up to 90 % of new capacity). It shows that this new wave of investment is characterized by a kind of technology shift.

*1 A large volume of investment in capacity*

The evolution of generating capacity in the United States between 1990 and 2002 shows a pronounced change in pace during the recent “competitive” period of 1998–2002. During the eight years preceding the pivotal year of 1998, total production capacity only increased by 44 GW, or about 5 per cent, while during the four years following 1998 this capacity rose by 155 GW—about 20 per cent. This represents a genuine leap forward in generation capacity (Hunt 2002).

However, since a number of U.S. states either did not embark on these competitive reforms, or did so belatedly, there is some room for doubt concerning the link between the evolution of total volume of capacity and the reforms. This is why we must look at the distribution of these capacities between the electricity utilities (being the traditional regulated companies from before the reforms) and the independent power producers (the IPPs). These “independent” generators, though they may have been created before the competitive wave of the late 1990s and owned by the utilities, nonetheless represent one of its key features, because such generators work outside the traditional regulatory framework applied to utilities since decades<sup>4</sup>.

In the eight years following 1990, total capacity owned by the utilities declined by 7 GW (–1 %) while that owned by the Independent Power Producers (hereafter IPPs) increased by 28 GW (+ 300 %, either by construction or acquisition from the utilities). However, during the four years after 1998, being the true start of the competitive era, the capacity owned by the

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<sup>4</sup> It has to be remembered that in the USA expressions like “*Independent Generators*” or “*Independent Power Producers*” could refer to really new entrants as well as to new subsidiaries created by the old utilities under the umbrella of new laws (like *PURPA – Public Utility Regulatory Act* in 1978- favouring the creation of “*Qualifying Facilities*” –QF; which has a right to sell energy to utilities at a favourable regulated rate - in Combined Heat & Power –CHP- or in renewable energy).

utilities truly fell substantially, by 132 GW (–18 %), while that owned by the IPPs shot up 271 GW (+700 %, either by construction or acquisition as new subsidiaries of the utilities). The strong growth in investments during the early competitive period 1998–2002, which appears to be without precedent in terms of volume, is thus particularly characterised by the actions of the IPPs. They not only accounted for the bulk of investments in new capacity, but also substantially dismantled the installed base of power plants managed by the utilities. When these four exceptional years ended in 2002, the IPPs found themselves owning a generating capacity of nearly 310 GW, or over half as much as the traditional utilities (597 GW) [see Annexe N°1]. It is true these IPPs can be subsidiaries of the utilities, particularly from other states. But this does not negate the special role they have played in this massive wave of recent investment in generation.

If we now concentrate on only two of the most extensive competitive reforms in the United States, California and Texas, (representing a total of nearly 130 GW in capacity in 1998), we find again evidence of intense investment in generation (+ 20 GW overall) between the years 2000 and 2002. The increase in capacity attains 10 % in California, and 30 % in Texas where we observe a “boom” in capacity [see Annexe N°2].

In Europe, two countries also witnessed considerable investments in generation under the competitive reforms (totalling approximately +45 GW). First, in England and Wales the equivalent of 40 % of the initial capacity was added during the first decade of the reform, while Spain added nearly 30 % in five years. Italy also created nearly 6 % in new capacity in the first four years. Only Norway’s capacity had scarcely changed (+3 %) ten years after the competitive reform [see Annexe N°3].

## *2 A profound change in technology: the “Dash for Gas”*

While in the first years of the competitive era in the United States, the growth of capacity investment was unprecedented, the evolution of the fuel mix too presents a break during this post-1998 competitive period (see Annexes N°4 and N°5). Previously, between 1990 and 1998, coal and nuclear technologies dominated generation in the United States with 56 % (in 1990) and 54 % (in 1998), while gas (gas only or dual fuel—oil and gas<sup>5</sup>) accounted for about one quarter (23 and then 27 %). During the first competitive period 1998–2002, gas-based

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<sup>5</sup> Until 1995 gas plants in the USA favoured the old gas technology existing before the CCGT.

systems jumped to 38 % of capacity (of which approximately 20 % was gas only), while coal and nuclear fell well below half at 45 %. In fact, in absolute value, coal and nuclear generation capacity remained unchanged over these four years of technological change, with 338 GW and 105 GW, respectively. It is rather the expansion of gas (+113 GW) and dual fuel (+38 GW) that opened the technological rift. New capacity in these two gas-based technologies represented 97 % of incremental output in the United States between 1998 and 2002.

The comparative evolution of the capacity and fuel mix of the utilities and the IPPs is also very significant (see Annexes N°4 and N°5). In 1990, the IPPs generated 90 % of their output from hydro and other renewable energy sources. Between 1990 and 1998 increased capacity of the IPPs in the two gas-based technologies (gas only and dual fuel) represented 49 % of total growth in these technologies in the United States, while the corresponding number for the utilities was only 11 %<sup>6</sup>. Consequently, by 1998 the two gas technologies accounted for 52 % of the IPPs' installations, while hydro and other renewable amounted to only 28 %. However, at 10 GW, the "gas only" capacity of the IPPs was only one quarter that of the utilities. Between 1998 and 2002, the increase in the IPPs capacity in the two gas technologies represented 99 % of the total growth in these technologies in the United States. While the utilities' additional "gas only" capacity only amounted to 8 % of that total, their capacity in dual fuel fell by 16 % (the utilities converted or sold to the IPPs some 24 GW of their dual fuel capacity). After this short period of intense technological change, the IPPs' "gas only" capacity was 99 GW in 2002 and nearly twice as large as the utilities' "gas only" capacity. Overall, 55 % of the total generation capacity of the IPPs consists of gas or dual fuel, as opposed to 26 % in the case of the utilities.

As a result, it is really established that the first years of the competitive era opened a sweeping and rapid technological switch to gas in the United States, and that it is actually closely linked to the competitive reform. The technological evolution of two big competitive reforms in the United States (California and Texas) thus corroborates the overall American data. In the additional capacity that came online, around 30 GW was powered by natural gas. In California and Texas virtually all post-1998 capacity addition was in gas-based technologies [see Annexe N°6].

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<sup>6</sup> The balance was accounted for by a third type of actor: Combined Heat & Power Producers –CHP–.

In Europe, the technological evolution of the three competitive reforms having invested in generating capacity, England and Wales, Spain, and Italy, mirrors that of the United States. Overall, over 32 GW of gas-based generating capacity was built in these three countries. This exceeds their total expansion in capacity (+27 GW). The dominant technology of new British and Italian development is gas, at between 75 and 95 % of the total capacity change. In Spain, a strong programme of support for renewable energies (especially wind power) has limited new gas capacity to 43 % of the total capacity change [see Annexe N°7].

## ***II Economic determinants of the new dominance of gas-based technology***

The fact that the fuel mix could change subsequent to a major upheaval like the competitive reforms was an open question before the reforms. However, given the technological changes seen after liberalisation and privatisation in the airline industry (with the expansion of the “Hub & Spokes” model) and in the telecom industry (with the expansion of digital technology and wireless network) (Bailey, Graham & Kaplan 1985; Vickers & Yarrow 1988); an energy technology change was not seen as impossible. Notably coal, as a heavily subsidized fuel in Europe, was seen as going to suffer. Nonetheless, predicting the sequence of changes that would follow the competitive reforms with any precision was rendered difficult because of the wide array of possible inefficiencies under the former regime where cost and technologies were submitted to public regulation and public energy policy, and resulted into prices being imposed to customers through franchised monopolies [Joskow & Schmalensee 1983; Beesley & Littlechild 1983]. Several inefficiencies might have distorted the choice of generation technologies under the old regime of regulated production differently [Joskow & Schmalensee 1983, chap. 7 and 12].

On the purely theoretical front, Averch and Johnson demonstrated in 1962 that regulated firms could have a “*rational preference*” for the most capital-intensive technologies because their “Cost +” based price regulation was giving a guaranteed “rate of return” (ROR) to their invested capital. While the standard microeconomics was still asserting that the marginal pricing rule (*price = marginal cost*) was able to rationally frame the management of existing monopoly [Mishan, 1968; Turvey 1968; Turvey & Anderson 1977]. Further economic literature showed that economic theory has not improved much in the four last decades of the

XXth century in explaining how the regulated framework influences the electrical utilities in choosing their generating technologies (Pollitt 1995; Ishii 2004; Ishii & Yan 2004). In practice however, many countries had entrenched a fuel mix by promoting “national” combustibles (such as coal and lignite) through providing subsidies on their prices, or financing a national variant within a given technology (such as nuclear) [Newbery and Green, 1996]. In each of the U.S. states, regulators have also used a variety of means to influence the choices of their utilities. Especially because US regulators have the right to set regulated tariffs *ex post* (i.e: after the facts) by giving or not their approval to the evolution of the cost of generation (by ex. oil and gas prices could vary deeply from a period to another period, and not being totally past trough by the regulator) [Joskow and Schmalensee, 1986; Joskow, 1989; Joskow, 2003].

Quite aside from these general distortions, which can logically be laid at the feet of imperfect regulation, or the regulators’ preferences, or government energy policy, empirical studies have also discovered a whole universe of hidden inefficiencies of all kinds. These have been concealed as much by differences in construction costs as by the range of the operational performances of the main technologies (nuclear or fossil fuel), even within a single country, and even when account has been taken of the impact of the age and size of the plants and the precise characteristics of the fuel [Joskow and Rose, 1985; Joskow and Schmalensee, 1987; Joskow, 2002; Wolfram, 2003].

Even within this imprecise framework, it is reasonable to expect that extending competitive mechanisms and eliminating government funding would impose a strong competitiveness constraint on producers, and thus promote the adoption of those technologies that truly are the most efficient in generation [Littlechild, 1994; Pollitt, 1995]. The spread of gas-based technologies observed in Great Britain as of 1992–1993 is thus attributable to the fact that this emerging technology proved to be the cheapest at the point in time when the competitive reforms were coming into their own [Newbery and Green, 1996; Newbery 2000; Bower, 2004-b]. In the US, the same wave, occurring later, marked both a technology shift and the end of regulatory uncertainty [Hunt 2002; Ishii 2004; Ishii & Yan 2004].

### *1 The comparative competitiveness of gas and coal*

The economic benefits of new gas-based generating technologies have been demonstrated many times and in various places, usually with the traditional method for comparing electricity generation costs known as the “*levelised cost methodology*”. This methodology is in use since decades and predates the competitive reforms. It was, and continues to be, used as much by investors as by institutions and economists. Based on an estimate of the various types of costs (capital costs, operating and maintenance costs, fuel costs) and annual energy generation over the lifespan of a typical plant for a given energy system, it discounts the flows of costs and energy prices using reference rates (traditionally, 5 and 10 %). The result is comparable series of electricity generation cost levels that allow a “ranking by economic merit” to be established for choosing between alternative technologies [DGEMP, 1997 and 2003; EIA, 2000 to 2004; IEA, 1999, 2002 and 2003; Royal Academy of Engineering, 2004].

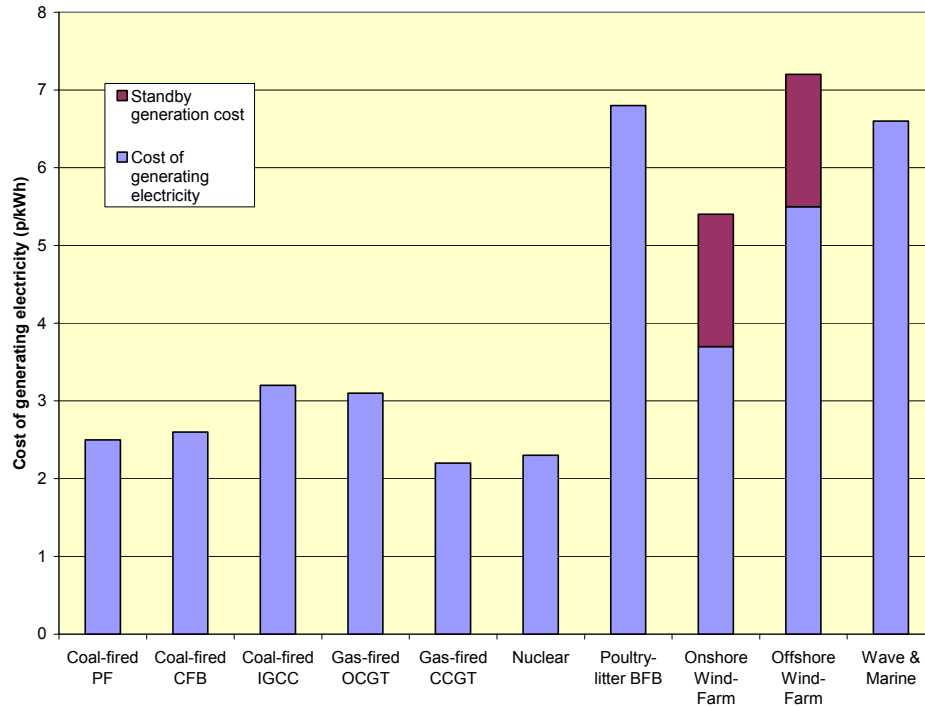
The new competitiveness of gas relative to coal was clearly of great economic importance in countries such as the United States and Great Britain, where coal dominated the fuel mix (60 % coal in British electricity capacity in April 1990; 44 % coal capacity for U.S. Utilities in 1990 and 1998)<sup>7</sup>. This competitive edge of gas was simultaneously substantial and enduring, since the most recent study of Britain’s Royal Academy of Engineering in 2004 continued to describe CCGT plants as the least expensive method available for generating electricity.

In the United States, studies by the Department of Energy (EIA-DOE) in 1996 predicted economic dominance for gas that would persist beyond the forecast horizon (2015) and featured a cost advantage of over 20 % in the average scenario (approximately \$8 per MWh). For the first time in a long while, these same forecasts, conducted in 2004, foresee that a greater competitiveness for coal could emerge between 2010 and 2025 (with a cost advantage of about 2 %, or \$1.2 per MWh, \$0.48 having been absorbed by higher network development costs explain this inclusion of network costs). Confirming this recent change, the February 2005 forecasts foresee 1/3 of the 2005-2025 coming new plants in the USA being coal fired with about 90 GW new capacity installed and 1 000 TWh of supplementary coal generation in 2025. However new gas plants are still considered as providing around 60 % of the expected 280 GW generation investment for 2005-2025 (See Annexes N°7 and N°8).

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<sup>7</sup> In turn, the French Ministry of Industry has recognised the competitiveness of the new combined cycle gas technology (CCGT) in the 1997 update of its *Reference Costs for Power Generation*—representing a break with the position taken in 1993. CCGT replaced coal as the benchmark traditional thermal energy. It dominated the mid-base and, in some scenarios, even the base load generation.

**Figure 1 - Present-Day Costs of Generating Electricity in UK (Year 2003/04)**



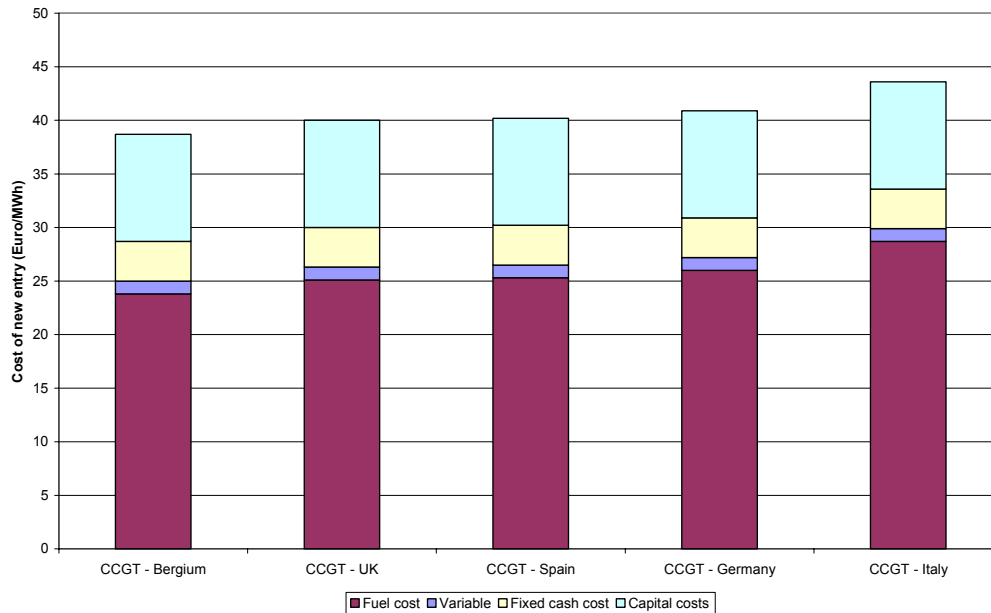
(Source: Royal Academy of Engineering, London, March 2004)

Of course, such studies are based on numerous assumptions, variants, and scenarios that cannot be discussed in detail here. The economic dominance of gas over coal is thus relative, not absolute. There are indeed several regions in which coal's competitiveness was never challenged by that of gas. In European studies conducted by investment banks, such as those of the Crédit Suisse First Boston, cost calculations are individualised country by country to better account for local conditions. For the same CCGT technology and the same forecasted entry into service in 2005, a difference of \$5 per MWh (or 13 %) is found to exist between Belgium and Italy.

The future competitiveness of these technologies will also depend on the "carbon price", trading in which has only begun in Europe. In scenarios developed in Oxford by John Bower, the price of a tonne of CO<sub>2</sub> is the key to the relative competitiveness of gas and coal, but also to that of existing power plants and investment in new British plants. With a price of carbon at 15 Euros / CO<sub>2</sub> ton, old nuclear is seen having a marginal cost in 2008-2012 smaller than 15 £

/MWh, old CCGT plants around 25 £, and old coal plants around 31 £ permitting them to temper the interest of investing into new CCGT plants [Bower 2004-a].

**Figure 2 – CCGT Cost of entry by country in Europe in 2005**



(Source : Crédit Suisse First Boston, March 2004, *Electricity Handbook*)

## 2 The comparative competitiveness of gas and nuclear

Since the beginning of the U.S. and British “Dash for Gas”, many studies using the levelised cost methodology have established that nuclear has become the most expensive baseload thermal technology. The same conclusion is found in studies by investment banks, such as those from the Crédit Suisse First Boston in 2004 (approximately 50 % production cost gap to the detriment of new investment in nuclear). Thus in the United States, during the past ten years the DOE’s Annual Energy Outlook has not foreseen any resumption of investment in nuclear power, regardless of the timeframe considered (1995–2025). Similarly, in its most recent *World Energy Investment Outlook*, published in 2003, the International Energy Agency does not foresee any new investment in nuclear in the United States or

Europe, except in France and Finland, throughout the thirty year period 2000–2030. An MIT study in 2003 set the cost spread of nuclear, gas, and coal at 25 to 50 % [MIT 2003].

In France the comparative analysis of the competitiveness of gas versus coal has made considerably less of an impression than the position of gas relative to nuclear. In a 1997 study by the Ministry of Industry [DGEMP 1997], new CCGT technology successfully undercut nuclear's domination of the baseload by assigning a price of 0.21 FF per kWh to the latter (for a series of ten nuclear reactors) compared to 0.19 FF for CCGT under several scenarios (a fall in the price of gas, increased thermal efficiency, lower construction costs). This reversal of technological prospects is quite abrupt relative to 1993 (only four years earlier), when the median cost advantage of French nuclear over coal (the only alternative envisaged at the time) was 30 %. However, to this date all French studies have consistently demonstrated the economic superiority of nuclear technology over those based on coal or gas in the median scenarios. The most recent study of reference costs by the Ministry of Industry [DGEMP 2003], describes a nuclear PWR operating at €28.4 per MWh in 2015 (using 2001 prices, or €29.9 at 2004 prices), that is 20 % cheaper than CCGT (€34.5). Since French calculations for gas and coal tend to yield approximately the same results as studies from other countries, this difference is entirely attributable to how the French Ministry analyses the costs of nuclear. Several other recent studies [Santaholma 2003, RAENG 2004, AREVA 2004], whether they concur with the French conclusions or not, have revealed that the discrepancies result from methodological differences and reflect divergences in the understanding of the impact of the competitive reforms on the comparative economic advantages of various generation technologies.

**Table 1 – Nuclear generation costs in the early XXIst Century (by MWh)**

Belgium-Ampere 2000	Finland 2001	France-DGEMP 2003	UK-RAE 2004	USA - MIT 2003
<b>30 €</b>	<b>24 €</b>	<b>28.4 €</b>	<b>33.8 €</b>	<b>67 \$</b>

(Source: Areva 2004)

### ***III The cost of capital as a key economic determinant of technology choice in a competitive framework***

It is common practice to rely on the traditional levelised cost methodology to evaluate the relative competitiveness of alternative technologies for generating electricity. This assumes, at least implicitly, that the costs and benefits of technologies can be computed with no regard for the context in which they are to be implemented (regulated monopoly or competition). This working hypothesis, even when implicit, is surprising. Indeed, the economic analysis of regulated monopolies suggests that their generation costs could have been poorly understood or controlled, especially since the risks inherent in the choice of technology and capacity were not borne by the producers, but rather by consumers [Joskow, 2000]. Conversely, in this new competitive framework these risks are borne by the producers themselves, *a priori*, and make up an essential element of the constraints guiding their behaviour [Joskow, 2003]. One essential feature of competitive electricity regimes is that these new constraints are activated by the absence of guarantees on the demand addressed to each firm and the level or evolution of market and input prices. These unconstrained movements in volumes and prices, which could lead to extreme volatility, introduce a new risk for producers. That volatility is more consequential for generators being not vertically integrated and selling their output mainly or entirely into wholesale markets with neither established customer base nor contractual price guarantee (like “*Merchant Plants*”, which are these Independent Power Producers having not contracting for their output). Furthermore, in a competitive electricity generation regime, producers have access to neither government subsidies nor government capital (both being “*State Aid*” in the EU competition framework). Therefore, the “cost of capital” for investments in generation becomes one of the producers’ key decision variables [MIT, 2003], in particular given the high level of capital intensity of the electricity industry [IEA, 2003].

### *1 Costs and risks specific to nuclear in a competitive regime*

The traditional framework for economic analysis of production costs, the levelised cost methodology, encounters a major snag when comparing very different technologies in the new competitive framework. To rank these technologies by cost, this method assumes that it is easy, or at least not too difficult, to translate the risk profiles of the various technologies into discounted cost levels.

In the traditional methodological framework, a first, simple way of expressing the technological component of the risks is to conduct sensitivity analysis. Thus, a sensitivity analysis of nuclear’s vulnerability to fuel cost variations, as in the 2004 Royal Academy of

Engineering study, confirms that nuclear technology insulates the generation process from randomness affecting the fuel. While the cost of generating of gas fired plants are shown to be sensitive up to 30 % to their fuel costs, with extreme gas price scenario making nuclear cheaper than CCGT [RAENG 2004].

However, since the principal costs and risks of nuclear lie outside of fuel costs, it remains to adapt the sensitivity methodology to this technology. The study published in 2003 by the MIT features a very interesting adaptation of this methodology to account for the new competitive environment in the United States that will frame any potential investment in American nuclear. The reference cost for nuclear in the MIT study is very high (\$67 per MWh), compared with €28.4 in the DGEMP's French study published the same year.

**Table 2 – Nuclear generation costs in the 2003 MIT Study**

<b>Total reference cost</b> (\$ / MWh)	<i>With reduced construction cost</i> (–25%)	<i>With reduced construction time</i> (5 years > 4 years)	<i>With reduced O&amp;M cost</i> (down to 13 \$ / MWh)	<i>With reduced cost of capital</i> (down to gas or coal cost of capital)
<b>67 \$</b>	<b>55 \$</b>	<b>53 \$</b>	<b>51 \$</b>	<b>42 \$</b>
	<b>Δ = 12 \$ (–18%)</b>	<b>Δ = 2 \$ (–3%)</b>	<b>Δ = 2 \$ (–3%)</b>	<b>Δ = 9 \$ (–13%)</b>

(Source: MIT 2003)

Nonetheless, this MIT study indicates how this high reference cost could be reduced in the United States by a concerted series of voluntary actions [Table 2]. Two primary levers for lowering costs are identified. First, the total cost of nuclear could be reduced by \$12 per MWh (–18 %) if construction costs (\$2000 per kW in the reference scenario) could be brought down to \$1500 (bringing them below the €1700 of the Royal Academy and near the €1300 level of the DGEMP study for a series of 10 reactors—at the exchange rate €1 = \$1.2). Second, total costs could also be reduced by \$9 per MWh (–13 %) if the cost of capital in nuclear could be brought to the same level as capital costs for gas and coal technologies.

The underlying economic reasoning is particularly relevant for our purpose. It underlines that a private investor runs much higher risks when choosing nuclear technology over gas or coal. Furthermore she cannot mitigate her own nuclear plant construction or management hazards by improving her knowledge or exploiting any series effect. Also, the competitive electricity market is much more unpredictable and volatile than the old regulated monopoly

market. “Merchant Plants” (Independent Generators) are particularly dependent of their wholesale market prices exposure. Thus, in terms of risk taking, nuclear runs completely counter to the choice of a “sensible” private investor. In the MIT study this is true for several reasons, all of which are adding their negative impact on the investors’ decision.

1. The real construction costs of nuclear are poorly defined, since they have not been the subject of a controllable experiment for a very long time and were difficult to control in the past.
2. The capital intensity of nuclear is three to four times greater (\$1500–\$2000 / kW) than that of a CCGT plant, and the unit size of a plant is two to four times higher. Thus, the unit cost of the minimal investment could be ten to fifteen times greater. Moreover, if reduced construction costs are attained by investing in multiple reactors (often ten units), the minimum size of a nuclear investment program is 10 to 16 GW (depending on the reactor technology), somewhere between \$15 and \$30 billions.
3. The timeframe for building a nuclear plant is inevitably long (at least five years in a very best-case scenario, versus two years for a CCGT plant), but also uncertain. This makes the timing of entry into the market considerably more random, while the per-unit generating capacity is also much greater than for a gas-fired plant.
4. There is no possible correlation between the evolution of the market price of electricity and that of the principal components of the cost of nuclear. This contrasts with the case of gas, for example, while this correlation, though imperfect, is effective (a substantial increase in the price of gas will have a positive impact on the wholesale price of electricity).
5. Finally, the operational performances of nuclear power plants are also varied and stochastic. This is particularly true for the capacity factor, where a minimum factor of 85 % is required for financial equilibrium of the nuclear project. In England the five AGRs units operated from 1990 to 1995 at a mean load factor of 61%, with the best unit at 78% and the worst at 36 % [Mac Kerron 1996]. Another source of randomness affects operating and maintenance costs, with a \$5 per MWh gap existing between current U.S. mean performance, at \$18 (fuel included), and its best quartile, at \$13.

Each of these specific components of the risk associated with nuclear are detrimental to the choice of this technology by an investor. The MIT study expresses this risk gap with a

structure and cost of capital that differs from that of gas-based technology. For a CCGT plant, the American investor needs only to supply 40 % of funding from equity (compensated at a rate of 12 %) and can borrow the remaining 60 % (compensated at 8 %). For a nuclear plant, the investor needs to supply 50 % of funding from equity (compensated at a rate of 15 %) and borrow the remaining 50 % (at the same 8 % rate).

This analysis of cost of capital specific to nuclear power plants is a major source of the cost differences between MIT and other studies (the Belgian, British, Finnish and French shown in Table N°1). However, a French recent study [IGF-CGM 2004] has shown that the current financial management of EDF now counts on a 13.7 % yield to equity in its nuclear generation. It is particularly striking because all existing French nuclear assets have been financed in the former framework of a regulated monopoly backed by the financial guarantee of the French State. This suggests that a new nuclear investment which would purely rely on “market based” private financing could not expect a lower return. Then a lower average cost of capital cannot come from a lower yield to equity and will crucially depends on the amount and rate of long term debt or long term bonds the nuclear lender can find in the market. While all non MIT studies make no difference with a nuclear and a non nuclear investment, with a rate of return on equity and on debt [Table 3].

**Table 3 – Nuclear vs Gas CCGT cost of capital analysis**

Belgium–Ampere 2000	Finland 2001	France–DGEMP 2003	UK–RAE 2004	USA – MIT 2003
All capital at 5% discount rate	All capital at 5% discount rate	All capital at 8% discount rate	All capital at 7.5% discount rate	<u>CCGT</u> at 9.6 % (40 % equity at 12 %) +(60 % debt at 8%) <u>Nuclear</u> at 11.5 % (50% equity at 15 %) + (50% debt at 8%)

In conclusion, the 2003 MIT study suggests that competitive reforms have a real impact on the choice of generating technology and that they particularly weigh in on the choice between nuclear and gas. They primarily impact on the cost factor most characteristic of nuclear—its capital intensity. Nuclear technology is extremely capital intensive, requiring \$2000 /kW in construction costs in the United States (aside from the cost of capital and interest over the construction period) and yielding an annual energy volume of 7.4 MWh with median annual sales of approximately \$320. The sensitivity of nuclear to investors’ financial behaviour is thus not comparable to that of other technologies. If, in addition to this core

characteristic, nuclear technology also features a large number of uncertainties in terms of costs and yields, the US capital markets cannot deal with it on the same footing as the other technologies.

However, since the functioning of capital markets is not unified internationally nor stable over time, the MIT study does not allow any precise conclusions to be drawn concerning the financing of future nuclear investment in France. The 8 % borrowing rate and 15 % yield to stockholders used by the MIT study may appear too high given current financial conditions in France. A recent French report already mentioned [IGF-CGM, 2004] places the cost of debt at under 5 % (with a good credit rating), while the new standard for yield to equity adopted by EDF is currently 13.7 %. However, there is no more guarantee that EDF will be able to easily find very long term loans (30 years and more) or the required equity. The former period of unlimited financing for nuclear at the bond-market rate with the guarantee of the government of France is over. A 50/50 financing split between equity and debt will constitute a challenge for the French nuclear champion, which would need to mobilize about €40 billion in equity to recreate its current nuclear base, after 2017 –the foreseen date of the first plant closure [Glachant & Finon 2005]-, at the current French Ministry’s construction costs (DGEMP). Another recent official report to the French Minister of the Economy, Finances and the Industry suggested that the actual amount of equity at EDF is probably nil, or even negative, for the fiscal years 2004 and 2005 [Roulet, 2004].

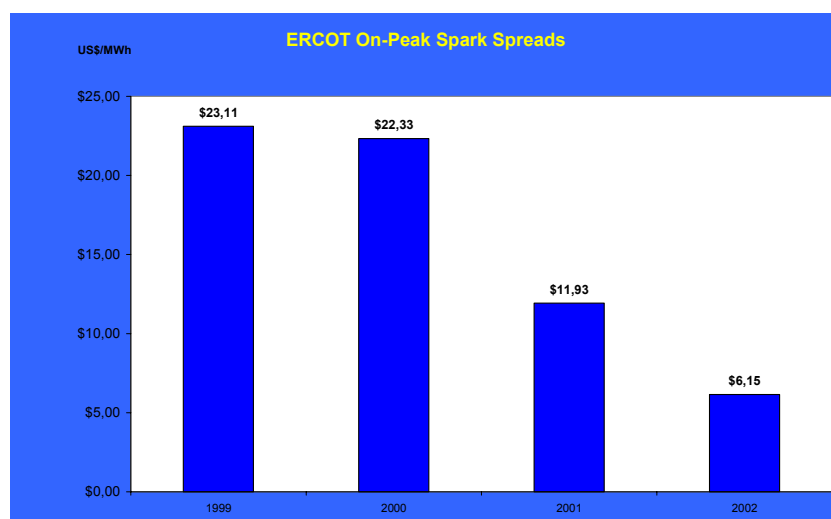
## *2 Comparison of costs and risks specific to nuclear and gas in a competitive regime*

If nuclear generation technology appears so sensitive to the competitive reform, then gas technology is as well, but in a different fashion. The bursting of the American electricity “bubble” in 2002–2003 revealed that the massive flow of IPP investment in gas-based generation capacity did not represent a sustainable financing or investment regime [Joskow, 2003]. Clearly, both the IPPs and their bankers had underestimated the risks of independent generation remunerated exclusively on the wholesale market’s terms and unable to rely on either a portfolio of end clients or a long term sales contract.

A retroactive computation of the “spark spread” (the gap between the wholesale price of electricity and the fuel cost of the gas necessary to generate it) reveals the evolution of producers’ “net” revenues and how the IPPs experienced the floundering of the wholesale

electricity market under the impact of the new overcapacity. In Texas, CCGT capacity increased by 23 GW between 1999 and 2002 while the On-Peak spark spread decreased from 23 to only 6 \$ a MWh [Figure 3] to face about 11 \$ capital costs and about 5 \$ O&M costs!

**Figure 3 – Spark Spread in Texas 1999-2002**



(Source: de Luze, 2003)

More generally, during the quarters following the Enron bankruptcy in the autumn of 2001, the business model made of merchant plant to generating electricity and trading platforms to selling it on wholesale market, which typified the first period of the U.S competitive reform, collapsed in the United States. The stock market values of the main pioneers of the reforms (AES, Williams, Calpine, El Paso, Mirant, Reliant, Dynegy, etc.) fell 90 to 95 % between the spring of 2001 and the spring of 2003, resulting in a \$130 billion loss in stock value (excluding Enron), while their credit ratings fell to between BB- and B-. Securities representing their numerous bond issues were negotiated at below face value, by – 15 to –75 %. New flows of bank and bond financing into the U.S. electricity sector fell by  $\frac{3}{4}$  (–\$30 billion) between 2001 and 2002 [de Luze, 2003]. Consequently, many of the IPPs' assets have ended up in the hands of their bankers, while any future financing of IPPs that do not have sales contracts for their output appears to be out of the question. Thus, the business model of the American electricity sector is reverting to one of vertical integration between generation and sales, either in the traditional form of a utility, or in the surrogate form of an

IPP covered by a long-term sales contract [Joskow, 2003; CERA, 2004]. [Newbery 2000] showed how this “vertically integrated” competitive model differs from a pure “vertical unbundling” framework when it comes to invest in generation. The entry of new generators in England & Wales has been favoured in the “dash for gas” by the hedging effect played by the long term contracts (15 years) these generators signed with the regional distribution monopolies (the RECs).

Nonetheless, despite the severity of the financial correction that struck the IPPs in the USA, their stockholders, and their bankers, no shift in technology choice has been induced. Gas-based generation has remained the norm. It is not the technology itself it is the business model that has shifted in the United States. The U.S. competitive reforms are evolving toward different forms of vertical integration between generation and the final sale, with no “technological correction” for the excesses of the gas bubble until the rise of gas price push for such a change. The main correction needed after the US “Gas Bubble” was a capacity adjustment to dry the existing overcapacity [see Green 2006].

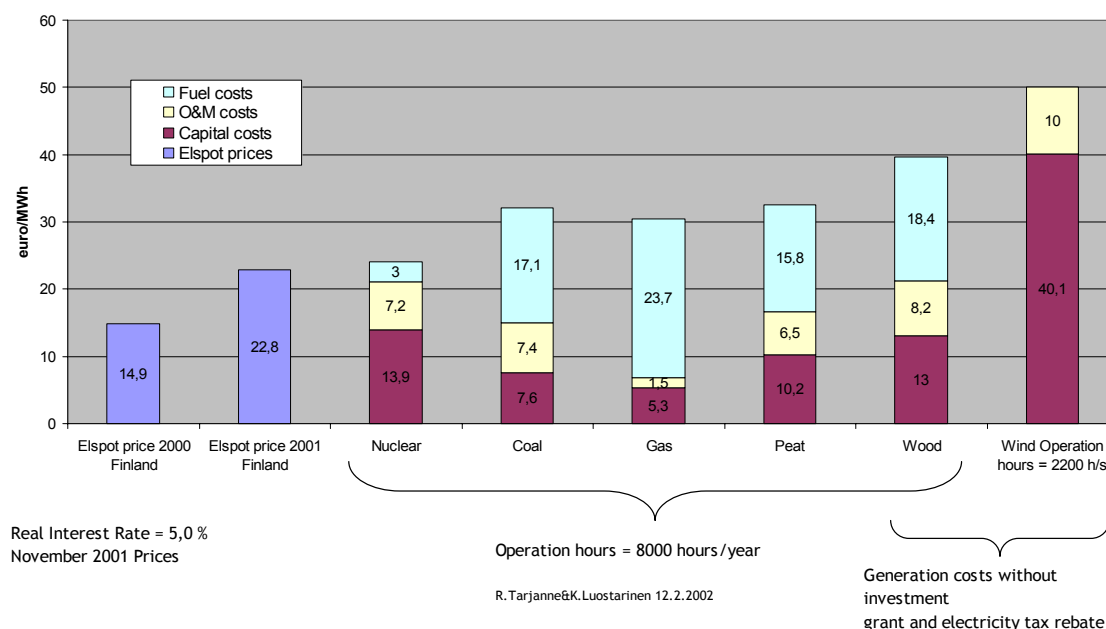
The constancy of technological choices after a bubble and a shock of this magnitude may surprise. Under precisely these conditions, nuclear technology remains a candidate for a radical rethinking of cost comparison methodologies that would allow the option value it represents to be captured. The fact that nuclear costs are not correlated with the standard market costs has to be properly valued. Several interesting academic studies have been working along these lines. [D. Newbery and F. Roques 2004] seek to substitute Monte Carlo simulations for the levelised cost methodology to compare the “complete” risk profiles of alternative technologies (coal, gas, and nuclear), and then generate a measure of the option value of nuclear as a hedge against higher gas and coal prices. [Gollier and Proult 2004] propose a measure of the option value of a new, and much more “modular”, nuclear technology in which the investor could decide to successively build 1, 2, 3, or 4, 300 MW modules and where the investment cost diminishes with each additional module. But none of these studies calls for any link to an existing or coming investment.

Thus, the current Finish example of a group of electricity distributors and large industrial clients co-financing a nuclear reactor (to be built by the French firm AREVA) remains an isolated empirical instance to account for. According to [Santaholma 2003], President of the Finnish Energy Industries Federation, this investment could represent 10 % of the capacity used during peak hours in Finland. While this project has the status of a national project

(publicly supported by the government, parliament, and labour unions), it is financed by TVO, a cooperative of local utilities and large industrial consumers. It will resell at cost price a volume prorated to reflect each participant's share in the investment. Given the three assumptions that total equipment costs will be €1750 per kW (including all cost of capital fixed at 5 %), that reactor operation is expected a capacity factor of 91 % (or 8000 h annually), and that the included O&M fuel cost will be €10.2 per MWh, the mean cost per MWh is announced at €24, versus €32 for a CCGT plant -all values for Year 2000- [Figure 4].

This Finnish example illustrates that, within the framework of a very long-term contract (40 years) financed by the future energy buyers and transferring all risks onto these buyers along with a very low cost of capital, it is possible to end with very low values for capital cost and other costs (construction and O&M cost uncertainty being transferred to the energy buyers). In some ways, the cost analysis associated with the nuclear investment in Finland expects to reproduce the conditions of the French nuclear programme of the 1970s–1980s within the framework of the existing European competitive reform.

**Figure 4 – Finnish comparison of generation costs**



(Source: Santaholma 2003)

Today, in France, other paths, more or less similar, are being explored to bind industrial clients to EDF with long-term contracts [IGF-CGM, 2004] or to establish durable links between other electricity concerns in Europe and France's nuclear capacity [Glachant & Finon 2005]. It is hoped that the dire predictions emanating from the United States regarding the structural handicap impeding nuclear technology in a competitive investment environment can be countered by the vertical integration of generation with final sales or using long-term contracts, the construction of large series of reactors and plants by very big concerns, the accumulated expertise of a world nuclear leader, very favourable credit ratings for this type of borrower and very longer term debt (up to 30 years), as well as consideration of the option value of nuclear against a possible rise in the prices of fossil fuels and the price of carbon emission permits. The actual results of a new French nuclear case will be tested as soon as prototypes of the new nuclear reactor EPR will be built in France (in the coming years), but large scale closure of existing nuclear plants is not foreseen before 2020 and could be delayed more a decade.

### *Conclusion*

We have observed that the investment phases of the current competitive reforms in the electricity sector have been accompanied by a strong preference for gas-based generation technology, in particular for combined-cycle (CCGT) plants, of which 150 GW have been built in the United States and 32 GW in England, Spain, and Italy.

Many studies attribute the new dominance of this gas technology to its lower cost compared to coal and nuclear technologies. These studies assume that the electricity reforms only accelerated the recognition of this "gas" greater efficiency and forced the hands of generators by introducing competition and curbing government subsidies or other State aids. This analysis of the reversal of the ranking of total coal and gas technology costs was broadly accepted during the 1990s and could, in facts, be overturned again in the United States due to the current gas prices. However, the "ranking by economic merit" between CCGT and nuclear technologies remains contested in France by the ministry of industry...and by Britain's Royal Academy of Engineering.

The MIT's study has allowed two causes of the divergence in the cost analysis of nuclear to be clearly identified. First, the baseline costs of nuclear technologies (construction and

dismantling costs, operating and maintenance costs) and their operational performance (in particular the availability of plants and their lifespan) remain imprecise and highly variable. Second, characteristics that are intrinsic to investment in nuclear (especially: fixed R&D costs, capital intensity per kW, reactor and plant minimal size, construction time, lack of correlation between input costs and the price of electricity) increase the risks assumed by the investor in a competitive framework. While nuclear has a potential value as a hedge against the current rise of fossil fuel prices and of carbon emission costs, the setbacks experienced by the UK nuclear generator (British Energy, having to be saved by direct State Aid) demonstrate that the commercial survival of nuclear in a competitive environment is not assured even when plants are already built. It is therefore understandable that in a competitive environment the cost of capital for investments in nuclear could be driven up relative to that for gas or coal. Particularly when the investment is not to be made by an old and large vertically integrated Utility having a long record of honourable nuclear performances. All this set of items undercuts the competitiveness of nuclear—a technology at least three times more capital intensive than gas.

In the United States, the bursting of the CCGT investment “bubble” and the financial crisis confronting independent power producers, as well as the bankruptcy of Enron and the collapse of the “*merchant plant + trading*” model, have not succeeded in rehabilitating nuclear technology on a pure market base (the recent US Energy Bill is not contradicting). They have, rather, exacerbated the nuclear typical problems by raising the cost of capital to all electricity generation projects. In Europe, however, or at least in Finland and France, nuclear professionals claim to be able to fully manage the risks and costs specific to nuclear. All they need now is for capital markets to share that analysis. The privatisation of the French nuclear champion EDF could provide an occasion for these markets to give their first feedback.

## Annexes

### Annexe 1 – Generation Capacity in the USA 1990–2002

<u>PRODUCER TYPE</u>	<u>NAMEPLATE CAPACITY (Gigawatts)</u>
<b>YEAR 1990</b>	
TOTAL INDUSTRY	781
Utilities	735
IPP	9
<b>YEAR 1998</b>	
TOTAL INDUSTRY	825
<i>Change Total Industry 1990–1998</i>	+44
Utilities	728
<i>Change Utilities 1990–1998</i>	–7
IPP	37
<i>Change IPP 1990–1998</i>	+28
<b>YEAR 2002</b>	
TOTAL INDUSTRY	980
<i>Change Total Industry 1998–2002</i>	+155
Utilities	597
<i>Change Utilities 1998–2002</i>	–131
IPP	308
<i>Change IPP 1998–2002</i>	+271

(Own calculations<sup>8</sup> – data from IEA, *International Energy Agency*)

### Annexe 2 – Generation Capacity in California and Texas

<u>STATE</u>	<u>Installed Capacity (Gigawatts)</u>	<u>Annual Variation (%)</u>
<b>CALIFORNIA</b>		
Year 1998	54.3	
Year 1999	54.1	–0.6%
Year 2000	54.1	0%
Year 2001	57.2	+5.7%
Year 2002	59.5	+4.0%
<i>Total Change 1998–2002</i>	+5.2	+9.6%
<b>TEXAS</b>		
Year 1998	78.2	
Year 1999	79.9	+2.2%
Year 2000	86.8	+8.6%
Year 2001	94.0	+8.3%
Year 2002	101.7	+8.2%
<i>Total Change 1998–2002</i>	+23.5	+30%

(Sources: EIA *Electric Power Annual* [Energy Information Administration], DOE, USA; PJM Reports)

<sup>8</sup> Note: a third producer category (CHP: Combined Heat & Power) is not presented.

**Annexe 3 – Generation Capacity in Norway, England & Wales, Spain and Italy**

<u>COUNTRY</u>	<u>Installed Capacity (Gigawatts)</u>	<u>Variation (%)</u>
<b>NORWAY</b>	-	-
Year 1991	27.1	
Year 2002	28.0	
<i>Change 1991–2002</i>	+0.9	+3.3%
<b>ITALY</b>		
Year 1998	75.0	
Year 2002	79.2	
<i>Change 1998–2002</i>	+4.2	+5.6%
<b>ENGLAND &amp; WALES</b>		
Year 1990	63.9	
Year 2000	71.6	
<i>Change 1990–2000</i>	+ 7.7	+12%
<i>Capacity Additions 1990–2000</i>	+25.0	+39%
<i>Capacity Closures 1990–2000</i>	-17.3	-27%
<i>Capacity Mothballed in 2000</i>	5.4	8%
<b>SPAIN</b>		
Year 1998	49.1	
Year 2003	63.6	
<i>Change 1998–2003</i>	+14.5	+29.5%

(Sources: Statistics Norway and NVE; British Electricity Association; GRN; REE)

**Annexe 4 – Generation Fuel Mix in the US (1998–2002)**

<u>YEAR</u>	<u>PRODUCER TYPE</u>	<u>ENERGY SOURCE</u>	<u>ENERGY MIX (%)</u>	<u>GENERATION CAPACITY (Megawatts)</u>	<u>CAPACITY CHANGE 1998-2002 (%)</u>
1998	Total Electric Power Industry	Coal	41,0%	337 800	
1998	Total Electric Power Industry	Petroleum	5,5%	45 300	
1998	Total Electric Power Industry	Natural Gas	10,0%	82 100	
1998	Total Electric Power Industry	Dual Fired	17,2%	142 100	
1998	Total Electric Power Industry	Other Gas	0,0%	0	
1998	Total Electric Power Industry	Nuclear	12,7%	104 800	
1998	Total Electric Power Industry	Hydroelectric	11,6%	95 500	
1998	Total Electric Power Industry	Other Renewables	2,0%	16 400	
1998	Total Electric Power Industry	Other	0,1%	900	
	<b>TOTAL INDUSTRY (Year 1998)=</b>		<b>100,0%</b>	<b>824 900</b>	
1998	Electric Generators, Electric Utilities	Coal	44,0%	320 600	
1998	Electric Generators, Electric Utilities	Petroleum	5,9%	42 800	
1998	Electric Generators, Electric Utilities	Natural Gas	5,8%	42 400	
1998	Electric Generators, Electric Utilities	Dual Fired	17,0%	124 000	
1998	Electric Generators, Electric Utilities	Other Gas	0,0%	0	
1998	Electric Generators, Electric Utilities	Nuclear	14,4%	104 800	
1998	Electric Generators, Electric Utilities	Hydroelectric	12,5%	91 100	
1998	Electric Generators, Electric Utilities	Other Renewables	0,3%	2 200	
1998	Electric Generators, Electric Utilities	Other	0,0%	200	
	<b>TOTAL UTILITIES (Year 1998)=</b>		<b>100,0%</b>	<b>728 100</b>	

1998	Electric Generators, Independent Power Producers	Coal	17,7%	6 600	
1998	Electric Generators, Independent Power Producers	Petroleum	2,1%	800	
1998	Electric Generators, Independent Power Producers	Natural Gas	27,6%	10 300	
1998	Electric Generators, Independent Power Producers	Dual Fired	24,4%	9 000	
1998	Electric Generators, Independent Power Producers	Other Gas	0,0%	0	
1998	Electric Generators, Independent Power Producers	Nuclear	0,0%	0	
1998	Electric Generators, Independent Power Producers	Hydroelectric	8,5%	3 200	
1998	Electric Generators, Independent Power Producers	Other Renewables	19,7%	7 300	
1998	Electric Generators, Independent Power Producers	Other	0,0%	0	
	<b>TOTAL IPP (Year 1998)=</b>		<b>100,0%</b>	<b>37 200</b>	
2002	Total Electric Power Industry	Coal	34,5%	338 200	0,1%
2002	Total Electric Power Industry	Petroleum	4,4%	43 200	-4,6%
2002	Total Electric Power Industry	Natural Gas	19,9%	195 000	137,4%
2002	Total Electric Power Industry	Dual Fired	18,4%	180 200	26,8%
2002	Total Electric Power Industry	Other Gas	0,2%	2 200	**
2002	Total Electric Power Industry	Nuclear	10,7%	104 900	0,2%
2002	Total Electric Power Industry	Hydroelectric	9,8%	96 300	0,9%
2002	Total Electric Power Industry	Other Renewables	1,9%	18 800	14,9%
2002	Total Electric Power Industry	Other	0,1%	800	-12,3%
	<b>TOTAL INDUSTRY (Year 2002)=</b>		<b>100,0%</b>	<b>978 800</b>	<b>18,8%</b>
2002	Electric Generators, Electric Utilities	Coal	43,7%	260 600	-18,7%
2002	Electric Generators, Electric Utilities	Petroleum	4,3%	25 800	-39,7%
2002	Electric Generators, Electric Utilities	Natural Gas	9,2%	54 600	28,8%
2002	Electric Generators, Electric Utilities	Dual Fired	16,6%	99 200	-20,0%
2002	Electric Generators, Electric Utilities	Other Gas	0,0%	100	**
2002	Electric Generators, Electric Utilities	Nuclear	11,3%	67 400	-35,6%
2002	Electric Generators, Electric Utilities	Hydroelectric	14,7%	88 000	-3,5%
2002	Electric Generators, Electric Utilities	Other Renewables	0,2%	1 000	-54,3%
2002	Electric Generators, Electric Utilities	Other	0,0%	0	----
	<b>TOTAL UTILITIES (Year 2002)=</b>		<b>100,0%</b>	<b>596 700</b>	<b>-18,1%</b>
2002	Electric Generators, Independent Power Producers	Coal	21,7%	66 900	915,8%
2002	Electric Generators, Independent Power Producers	Petroleum	5,0%	15 400	1900,5%
2002	Electric Generators, Independent Power Producers	Natural Gas	32,1%	98 800	861,3%
2002	Electric Generators, Independent Power Producers	Dual Fired	22,8%	70 100	671,6%
2002	Electric Generators, Independent Power Producers	Other Gas	0,0%	0	**
2002	Electric Generators, Independent Power Producers	Nuclear	12,2%	37 500	**
2002	Electric Generators, Independent Power Producers	Hydroelectric	2,4%	7 200	130,0%
2002	Electric Generators, Independent Power Producers	Other Renewables	3,9%	11 900	62,4%
2002	Electric Generators, Independent Power Producers	Other	0,0%	100	**
	<b>TOTAL IPP (Year 2002)=</b>		<b>100,0%</b>	<b>307 900</b>	<b>728,0%</b>

(\*\*): one cannot do a division by 0.

Note: a third producer category (CHP: Combined Heat & Power) is not presented.

(Own calculations – data from IEA, International Energy Agency)

*Annexe 5 – Generation Capacity Changes in the US (1990–2002)*

<b>PRODUCER TYPE</b>	<b>MIX OF THE CHANGE (in %)</b>	<b>CAPACITY CHANGE (in Megawatts)</b>	<b>AS % OF THE INDUSTRY CHANGE</b>
<b>Capacity Change Total Industry 1990–1998</b>	<b>100,0%</b>	<b>+43 700</b>	<b>100,0%</b>
(Industry Capacity Change in Coal 1990–1998)	16,8%	+7 300	100,0%
(Industry Capacity Change in Petroleum 1990–1998)	-20,4%	-8 900	100,0%
(Industry Capacity Change in Gas 1990–1998)	49,0%	+21 400	100,0%
(Industry Capacity Change in Dual 1990–1998)	42,1%	+18 400	100,0%
(Industry Capacity Change in Nuclear 1990–1998)	-7,4%	-3 200	100,0%
<b>Capacity Change Total Utilities 1990–1998</b>	<b>-100,0%</b>	<b>-6 400</b>	<b>-14,6%</b>
(Utilities Capacity Change in Coal 1990–1998)	-27,2%	-1 700	-23,7%
(Utilities Capacity Change in Petroleum 1990–1998)	-156,7%	-10 000	112,5%
(Utilities Capacity Change in Gas 1990–1998)	-67,5%	-4 300	-20,2%
(Utilities Capacity Change in Dual 1990–1998)	138,1%	+8 800	47,9%
(Utilities Capacity Change in Nuclear 1990–1998)	-50,5%	-3 200	100,0%
<b>Capacity Change Total IPP 1990–1998</b>	<b>100,0%</b>	<b>+28 600</b>	<b>65,4%</b>
(IPP Capacity Change in Coal 1990–1998)	22,7%	+6 500	88,6%
(IPP Capacity Change in Petroleum 1990–1998)	2,2%	+600	-7,1%
(IPP Capacity Change in Gas 1990–1998)	35,5%	+10 100	47,4%
(IPP Capacity Change in Dual 1990–1998)	30,2%	+8 600	46,9%
(IPP Capacity Change in Nuclear 1990–1998)	0,0%	0	0,0%
(IPP Capacity Change in Other Renewable 1990–1998)	5,4%	+1 500	n.a.
<b>Capacity Change Total Industry 1998–2002</b>	<b>100,0%</b>	<b>+154 700</b>	<b>100,0%</b>
(Industry Capacity Change in Coal 1998–2002)	0,3%	+400	100,0%
(Industry Capacity Change in Petroleum 1998–2002)	-1,3%	-2 100	100,0%
(Industry Capacity Change in Gas 1998–2002)	72,9%	+112 800	100,0%
(Industry Capacity Change in Dual 1998–2002)	24,6%	+38 000	100,0%
(Industry Capacity Change in Nuclear 1998–2002)	0,1%	+200	100,0%
<b>Capacity Change Total Utilities 1998–2002</b>	<b>-100,0%</b>	<b>-131 500</b>	<b>-85,0%</b>
(Utilities Capacity Change in Coal 1998–2002)	-45,6%	-60 000	-15326,9%
(Utilities Capacity Change in Petroleum 1998–2002)	-12,9%	-17 000	816,9%
(Utilities Capacity Change in Gas 1998–2002)	9,3%	+12 200	10,8%
(Utilities Capacity Change in Dual 1998–2002)	-18,9%	-24 800	-65,2%
(Utilities Capacity Change in Nuclear 1998–2002)	-28,4%	-37 300	-21199,2%
<b>Capacity Change Total IPP 1998–2002</b>	<b>100,0%</b>	<b>+270 800</b>	<b>175,0%</b>
(IPP Capacity Change in Coal 1998–2002)	22,3%	+60 300	15398,5%
(IPP Capacity Change in Petroleum 1998–2002)	5,4%	+14 600	-703,5%
(IPP Capacity Change in Gas 1998–2002)	32,7%	+88 600	78,5%
(IPP Capacity Change in Dual 1998–2002)	22,5%	+61 000	160,5%
(IPP Capacity Change in Nuclear 1998–2002)	13,9%	+37 500	21299,2%
(IPP Capacity Change in Other Renewable 1998–2002)	1,7%	+4 600	n.a.

Note: a third producer category (CHP: Combined Heat & Power) is not presented.

(Own calculations – data from IEA, International Energy Agency)

**Annexe 6 – Generation Capacity Changes in California and Texas**

<u>STATE</u>	<u>Capacity Changes (Gigawatts)</u>	<u>Changes Fuel Mix (%)</u>
<b>CALIFORNIA</b>	-	-
Nuclear 1998–2002	0	0%
Coal 1998–2002	0	0%
Oil 1998–2002	0	0%
Gas 1998–2002	+6.3	121%
Dual Fuel 1998–2002	-1.4	-27%
Hydro 1998–2002	0	0%
Renewable & Others 1998–2002	+0.3	6%
<i>Total Capacity Change 1998–2002</i>	+5.2	100%
<b>TEXAS</b>		
Nuclear 1998–2002	0	0%
Coal 1998–2002	+0.1	0.4%
Oil 1998–2002	+0.3	1.3%
Gas 1998–2002	+22.8	98.7%
Dual Fuel 1998–2002	-1.2	-5.2%
Hydro 1998–2002	0	0%
Renewable & Others 1998–2002	+1.1	4.8%
<i>Total Capacity Change 1998–2002</i>	+23.1	100%

(Sources: EIA *Electric Power Annual* [Energy Information Administration], DOE, USA)

**Annexe 7 – Generation Capacity Changes in England & Wales, Spain and Italy**

<u>COUNTRY</u>	<u>Capacity Changes (Gigawatts)</u>	<u>As % of the Total Capacity Change</u>
<b>ENGLAND &amp; WALES</b>	-	-
Nuclear 1990–2000	+1.2	15%
Coal 1990–2000	-9.6	-124%
Oil 1990–2000	-4.2	-54%
Others 1990–2000	-1.8	-23%
Gas 1990–2002	+22.1	286%
<i>Total Capacity Change 1990–2000</i>	+7.7	100%
<b>SPAIN</b>		
Nuclear 1998–2003	+0.2	1.4%
Coal 1998–2003	+0.8	5.6%
Gas & Dual Fuel 1998–2003	+6.2	42.7%
Hydro 1998–2003	+0.1	0.7%
Renewable 1998–2003	+7.2	49.6%
<i>Total Change 1998–2003</i>	+14.5	100%
<b>ITALY</b>		
Gas & Dual Fuel 1998–2002	+3.8	73.0%
Hydro 1998–2002	+0.7	13.5%
Renewable 1998–2002	+0.7	13.5%
<i>Total Capacity Change 1998–2002</i>	+5.2	100%

(Sources: British Electricity Association; GRTN; REE)

*Annexe 8 - 1996 Forecasted Costs of Producing Electricity in 2000 and 2015*

<i>Item</i>	<b>2000</b>		<b>2015</b>	
	<i>Conventional pulverized coal</i>	<i>Advanced combined cycle</i>	<i>Conventional pulverized coal</i>	<i>Advanced combined cycle</i>
<b>1994 mills per kilowatthour</b>				
<i>Capital</i>	26.41	11.24	26.18	7.00
<i>O &amp; M</i>	10.72	4.82	10.72	4.82
<i>Fuel</i>	13.58	22.35	7.42	24.38
<b>Total</b>	<b>50.72</b>	<b>39.41</b>	<b>44.32</b>	<b>36.20</b>
<b>Btu per kilowatthour</b>				
<i>Heat rate</i>	9.840	7.300	8.142	5.687

(Source: EIA, DOE, *Annual Energy Outlook 1996*)

*Annexe 9 - 2004 Forecasted Costs of Producing Electricity in 2010 and 2025*

<i>Costs</i>	<b>2010</b>		<b>2025</b>	
	<i>Advanced coal</i>	<i>Advanced combined cycle</i>	<i>Advanced coal</i>	<i>Advanced combined cycle</i>
<b>2002 mills per kilowatthour</b>				
<i>Capital</i>	33.77	12.46	33.62	12.33
<i>Fixed</i>	4.58	1.36	4.58	1.36
<i>Variable</i>	11.69	32.95	11.74	37.91
<i>Incremental transmission</i>	3.38	2.89	3.26	2.78
<b>Total</b>	<b>53.43</b>	<b>49.65</b>	<b>53.20</b>	<b>54.38</b>

(Source: EIA, DOE, *Annual Energy Outlook 2004*)

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