Report to the Prime Minister

Economic Forecast Study of the Nuclear Power Option

Jean-Michel Charpin
Planning Commissioner

Benjamin Dessus
Director
of the Ecodev at the CNRS

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Engagement letter

The Prime Minister Paris, May 7, 1999

Dear Sir,

The Government would like to have a study concerning the economic data of the entire nuclear industry and in particular the later stages of the nuclear fuel cycle, including reprocessing. This study will take into account the various hypotheses contained in the "Energy 2010-2020" plan report and the international conditions of the energy economy. The economic comparisons will be carried out from this point of view in respect of the full costs of other energy sources, including external environmental costs. This study will integrate the various possible development scenarios up to a time horizon allowing the long-term costs of the industry's later stages to be taken into account.

I have requested that this study will be caried out by you in conjunction with Messrs René Pellat, High-Commissioner for Atomic Energy and Benjamin Dessus, Director of the ECODEV programme at the CNRS. I would like to thank you for agreeing to do so.

You may rely notably on the work concerning the later stages of the fuel cycle carried out by Mr Mandil, Director General of Energy and Raw Materials at the Ministry of Economy, Finance and Industry, and Mr Vesseron, Director of Prevention, Pollution and Risks at the Ministry of Regional Development and Environment. In the same way, you may also take into account the evaluations prepared by the Ministry of Economy, Finance and Industry (1997 electricity generation reference costs), and the strategy reviews and programme of the Ministry of National Education, Research and Technology concerning research into the later stages of the fuel cycle conducted under the terms of the 1991 Act. Furthermore, the work of the Parliamentary Office for evaluation of scientific and technological choices, together with the reports from the National Commission for Evaluation will be helpful in performing your study .

I would like you to carry out a comparative analysis of the various methods of generating electricity and to examine all the factors on which a public decision must be based: inherent competitiveness, externalities and long-

term effects, such as the impact of the various generation methods on our CO_2 emissions and the management of the later stages of the nuclear cycle.

In order to ensure a relevant analysis of the relative economic performances of the various industries, you will define harmonised analysis methods, in particular as regards the optimisation and discounting criteria to be taken into account.

It is the Government's wish that you should work in collaboration, where necessary, with the departments of the main corporations and bodies of the nuclear industry, among them the Commissariat à l’Energie Atomique, Electricité de France, Cogema, Framatome, ANDRA and the CNRS. It will also be desirable to gather experience acquired outside France on these subjects and to enlist the support of economic research teams.

The French Planning Office (Commissariat Général du Plan) will act as your group's secretariat. I would like that your report will be submitted to me no later than the end of March 2000.

For the purposes of this study, you will have to contact the Minister of National Education, Research and Technology, the Minister of Regional Development and Environment, the Minister of Economy, Finance and Industry, the Secretary of state for Industry, and the members of the Government directly concerned by this study.

I am sending a copy of this letter to the General Manager of the CEA, to the Chairmen of EDF, Cogema, Framatome, ANDRA and to the Director General of the CNRS, asking that they provide comprehensive responses to your requests for information.

Yours sincerely.

L. Jospin

Lionel JOSPIN

Monsieur Jean-Michel CHARPIN
Commissaire au Plan
Commissariat Général du Plan
18, rue de Martignac
75700 Paris 07 SP

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Monsieur Benjamin DESSUS
Directeur du Programme ECODEV
CNRS
1, rue du Cerf
92195 Meudon Cedex

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Monsieur René PELLAT
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Commissariat à l'Energie atomique
31-33, rue de la Fédération
75762 Paris Cedex 15

Introduction

In his letter of May 7, 1999, the Prime Minister requested that we conduct "*a study concerning the economic data of the entire nuclear industry and in particular the later stages of the nuclear fuel cycle, including reprocessing"*. The study was intended to include comparisons with the cost of other means of producing electricity and to take into account the environmental costs.

We quickly agreed to respect in a severe manner the terms of this request. The study that we have produced covers the technical, financial and ecological factors. In addition to meeting the requirements of the Prime Minister's remit, our approach also offers two key advantages. First we have had to undertake our own detailed analysis of all the information needed to carry out the study. This is particularly important in a field where doubt is often expressed as to the accuracy and even trustworthy nature of the information used. On the basis of the contrasting reviews carried out, we can be reasonably confident that our sources are reliable. At the same time, this strategy has allowed us to explain the main arguments for the negotiations in which government and operators will be involved. A broad cross-section of scenarios has been explored, with the purpose to cover the majority of the strategies envisaged in the context of public discussion. Each scenario has been the focus of in-depth study. We have also indicated clearly the parameters which, in our opinion, should be used as a matter of priority, in order to compare the various scenarios.

There is an evident disadvantage with the chosen approach. We have not sought to define what would be the most desirable future scenarios, let alone the resources needed to make them a reality. This study does not therefore put forward any recommendations. Those tempted to discern any by reading between the lines will do nothing more than reveal their own preferences. As for the major choices connected with the selected configurations in general, there is no one dominant scenario in relation with the determining criteria which we set ourselves, whether of an economic or environmental nature.

Our overriding aim, rather than to guide authorities in their choice or even influence public opinion, is to make it possible for the necessary democratic debate to take place on the basis of carefully examined information and reasoning explained in technical, economic and ecological terms.

Our study centres on two series of questions.

The ***first one*** focuses on existing nuclear facilities. In view of the inertia of a French electric power generation system based to a very large extent on nuclear energy and on which considerable investments have already been made, what leeway are public authorities and operators left with as far as the future of these installations is concerned ? Specifically :

- under what conditions and with what economic consequences could the service life of the existing facilities be extended ?

- what are the economic and environmental consequences of decisions aimed at continuing or halting the reprocessing of irradiated fuels from the existing facilities ?

The ***second*** concerns the new investments likely to meet, under a variety of hypotheses, the demand for electric power. In particular :

- what are the technologies (nuclear and non nuclear) that can be envisaged, and in what timeframe ?

- what are the major developments under way in the world likely to have an impact on the choices made in France ?

- what environmental consequences could these choices have by 2050, particularly in terms of greenhouse emissions and volumes of high level and long-lived radioactive waste ?

- what economic consequences will have these choices ?

The working method

In order to provide some answers to these questions and having taken account of works conducted previously, in particular by Messrs Mandil and Vesseron on the later stages of the nuclear cycle, the strategy reviews and programmes by the Ministry for National Education, Research and Technology, concerning research into the later stages of the cycle conducted under the terms of the 1991

Act, the work of the Parliamentary Office for evaluation of scientific and technological choices, as well as the reports produced by the National Commission for Evaluation, we have given priority to a method in which the selected scenarios aim to highlight the consequences of the various sequences of events and decisions. Alternative hypotheses have thus been examined regarding the growth in demand for electric power, the service life of the nuclear power stations currently in operation, the technologies available for the future, strategies in terms of reprocessing and the price of fuels.

The forward-looking analysis of the electric facilities is based above all on the description of electric power demand scenarios. For the same development in economic growth between 2000 and 2050, we have described two electricity demand growth hypotheses, the lower assuming a planned effort to bring demand for electric power under control.

This is followed by a description of the choices of electricity generation capacities in line with requirements. These capacities are differentiated in terms of :

- the share of centralised and decentralised power generation ;
- the organisation and capacity of natural gas supply networks and transport and electricity distribution networks ;
- the share of non-nuclear technology (mainly in respect of the combined natural gas cycles) ;
- the share and nature of the nuclear industries used (reactors and fuels).

We have made a particular effort to ensure the technical and economic data used for the various industries, nuclear, fuel and renewable, are consistent each other and have based our analyses on existing forward-looking scenarios. We have thus taken into account both the work of the 2010-2020 Energy Commission prepared by the French Planning Office (Commissariat Général du Plan) in 1998 and the forward-looking world scenarios available for 2050, in particular those produced by the International Institute for Applied Systems Analysis (IIASA) for the World Energy Council.

Analysis of the scenarios includes the presentation of materials balances prepared closest to the physical analysis. It also comprises calculation of the annual economic flows in terms of spending (investments, including those linked to natural gas supply networks and transport and distribution networks, exploitation, fuels) associated with each scenario from 2000 to 2050, on the basis of technical and economic information collected for each electricity generation and usage technologies. It produces a global comparison of the various discounted cost scenarios, calculated with a discount rate of 6 % for the next 30 years and 3 % thereafter.

Limitations of the study

These are connected, on the one hand, with the geographical and time-dependent constraints of our study and with the uncertainty associated with any long-term discussion, on the other.

- Geographic and time-dependent limitations
  - We deliberately limited our study to the analysis of France's demand for electricity and to the methods of meeting this demand nationally, at a time when the European electricity market is opening up. This choice is clearly a restrictive one in that the long-term existence of a European electricity market could prompt an optimisation of electricity generation facilities at European level and not France-wide.
  - France and Europe's dependence on a natural gas supply is only taken into account via the hypothesis concerning gas prices, with no quantitative fuel shortage anticipated. The impact on national employment has not been quantified.
  - For the most part, our economic analysis is based on economic flows for the 2000-2050 period. However we have emphasised the inescapable expenses, such as dismantling, provisionial storage and definitive waste storage, and production potential beyond this date, associated with the facilities existing in 2050. Furthermore, we have included some appraisal of the economic valuation of the facilities in place in 2050 for the various scenarios. The study therefore does nothing more than touch on the long-term consequences of decisions prior to 2050 (climate warming, supervision and maintenance of the very long-term nuclear waste stocks).
  - Similarly, in our analysis of the existing facilities, we have not tried to optimise their operations by integrating the consequences of decisions relating to new investments.

- Technical, economic and environmental uncertainties

In order to quantify the various scenarios, a series of forward-looking images have been used, both technical and economic in nature ; there is a certain degree of uncertainty about these images, as regards economic growth, the rate and extent of technical progress, and particularly the development in the cost of the various fuels. In this last topic and in order to take into account a sufficiently wide range of possibilities, we have used contrasting developments in fossil fuel prices, specially from a stagnant level beyond 1999 to a doubling by 2050 for the cost of the main fuel in question we mean, natural gas.

Contents of the report

Chapter 1 deals with questions concerning the existing stock of nuclear facilities and presents an analysis of the economic and environmental consequences of the choices still possible as to the service life of nuclear power plants and the later stages in the nuclear fuel cycle ; however it does not tackle the issue of renewing the facilities, as this problem is dealt with in chapter 5.

Chapter 2 assesses the international situation as far as the civil nuclear industry is concerned and highlights the recent internationalisation in environmental concerns linked to energy systems.

Chapter 3 takes an overview of the developments anticipated in terms of the various technologies concerning the management of electricity power demand, the generation of electricity using fossil and fissionable fuels and renewable energy sources as included in the various scenarios set out in Chapter 4.

Chapter 4 describes the chosen scenarios, differentiated by their associated demand electricity (high or low) and by the extent to which they rely on nuclear power (with nuclear industry options varying both in terms of the choice of reactors and fuels). It also contains the materials balances associated with each of these scenarios, with presentation of the cumulative balances between now and 2050 for CO_2 emissions and for high level and long-lived nuclear waste to be deposited or stored permanently.

Chapter 5, presents an evaluation of the economic flows corresponding to the various scenarios on the basis of the chosen economic hypotheses. Cost components by kWh for the various industries are produced on this basis. The economic estimate of the environmental externalities is addressed in this chapter by means of a valuation of the CO_2 emissions and the nuclear waste accumulated during the 2000-2050 period, on the basis of value ranges for CO_2 gas and transuranic elements (Pu + minor actinides) which are avoided.

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We would like to thank all the experts of the ANDRA, CEA, COGEMA, EDF and FRAMATOME which so kindly provided information and agreed to comment on our analyses. Our thanks go to the Ministry of Economy, Finance and Industry, the Ministry of Regional Development and Environment and the Ministry of Research for their support, in particular for the funding of specific studies. We would also like to thank the authors of the three reports [1] prepared at our request on "Le parc nucléaire actuel", "La prospective technologique de la filière nucléaire" and "La prospective technologique des filières non nucléaires", together with Enerdata which produced the projection model. Although we cannot be held liable for these reports, they are nonetheless annexed to our report as key documents. We would also like to express our gratitude to our two rapporteurs, Nicole Jestin-Fleury and Jacques Percebois, for their valuable contribution. Clearly we take full responsibility for the contents of the report. The fact that our career paths and personal development differ so much has enabled us to appreciate not only the difficulties but also the immense benefits of working together on a subject of such controversy. It is with great pride that we take joint responsibility for all the informations, analyses and conclusions contained in this study.

(1) They are available only in french.

Chapter 1

The legacy from the past for France

The evolution of the costs of the electricity produced by the nuclear plants developed in France from 1977 onwards is largely a tribute to past capital expenditure (building of nuclear plants, Eurodif uranium enrichment facility, La Hague reprocessing facility, Melox fuel manufactory, etc.).

Since the majority of those infrastructure costs are now paid off, the cost of producing a kWh of electricity is that much lower for nuclear plant operators. That situation could continue through to the end of the service life of the existing reactor fleet. The only capital outlay remaining to be made relates to the interim storage and definitive disposal of long-life waste.

In this chapter, we chose to calculate the balance of materials (fuels used and quantities of spent fuels and ultimate waste for disposal) and the economic balance of the current fleet of 58 PWR reactors separately from any new power plants to be built after the year 2020. Certainly, in doing so, we leave out the transitional situations between today's power plants and those of the future, which, if we were to pursue our nuclear policy beyond the lifetime of the current power plants, would justify further investment on such aspects as fuel manufacture or the recycling of certain waste types. Those transitional situations will be discussed via the scenarios presented in Chapter 4.

Knowing the technical characteristics of the current nuclear plants, calculating the balances proved easy. However, it leaves the operator with some latitude, particularly as regards the decisions of the nuclear safety authority, which influence the overall economic performances of the fleet.

1. The latitude associated with the fleet of reactors

This latitude depends :

- ***Firstly, on the service life of the existing nuclear plants***

Indeed, as the major portion of the capital investment is already paid and weighs heavily on the overall cost of the system, the lifetime of the nuclear plants has a major impact on the economic equilibrium of the system. Although prolonging the lifetime of the plants increases the electricity production for the same initial investment, it nevertheless involves quite considerable expenditure on upkeep. Achieving the optimum balance between lifetime and cost of upkeep will minimise the average price of the kWh over the lifetime of the fleet.

- ***Then, on the good or poor use made of the existing nuclear plants***

The productivity of the existing plants can be improved by adjusting various parameters, basically those that impact the energy content of the fuel and the utilisation of the power plants. Improving the energy efficiency of the fuel shortens the outage time for fuel reloading, saves on materials at the front end of the cycle, produces less waste at the back end of the cycle and increases annual electricity production.

Concerning fuel quality, we recall that the amount of energy released in the core of the reactor depends on the quantity of fissile materials and, to a lesser extent, the quantity of fertile materials contained in the fuel that was loaded into the reactor. When that quantity increases (for instance if the fuel is enriched so that it contains more ^{235}U, the fissile isotope of the uranium), the fuel produces the same amount of energy in the core each day but over a longer period, thereby increasing its combustion rate.

The utilisation of the nuclear plant is described by its load factor or capacity factor Kp (i.e. its real production compared to the theoretical yield of the same nuclear plant running at full capacity over the same period). The factor Kp is the product of the fleet availability factor (the period of time during which the plant is on-line generating electricity) and its utilisation factor (the real energy called over the period of availability).

The ability to improve the production capacity of the fleet depends on the following factors :

- the operator’s ability to reduce unplanned outages (i.e. the frequency and duration of random failures) ;
- the operator’s ability to reduce scheduled outages, i.e. to manage the power plants as efficiently as possible (by keeping down maintenance and refuelling times, the duration of ten-year inspections, etc.) ;

- the position of the nuclear plants in the load curve, since we are aware that using nuclear plants for anything other than base-load generation impacts the overall economics of the fleet.

- ***And lastly on the options taken up for the back end of the cycle***

Those options must be chosen from the range of possibilities still available. Decisions in particular that impact evolutionary strategies or perhaps that break with the current strategy have to take into account the technical, regulatory and economic conditions of their implementation in the industrial environment born of past choices.

This latitude also depends on the importance of the time factor in any decisions taken concerning the nuclear industry.

The time factor is particularly crucial in the nuclear domain. This is true in the ***production phase*** (the rate of renewal depends on the lifetime of the nuclear plants, if indeed renewal is appropriate) but also, and perhaps particularly so in the fuel cycle, especially the ***back end of the cycle***. The characteristics of the spent fuel (its extremely high radioactivity and heat release, diminishing over time) bring the time factor into the equation. The different stages of the back-end, whether an open cycle (direct disposal of the spent fuel) or "closed" cycle (reprocessing-recycling of the re-usable uranium and plutonium materials and definitive disposal of the wastes) must therefore take into account various time-related effects such as :

- ***Reduction in heat emission***

This factor is determinant for the disposal of the spent fuel or of the materials making up the spent fuel after separation, because the amount of heat emitted conditions the storage volume required for a given type of waste, and therefore the cost of that storage. For instance, the heat emitted by spent MOX is very much greater on average [1] than the heat emitted by spent UOX : this implies either placing the MOX fuel in interim storage for a longer period prior to definitive disposal, or storing less MOX in the same space. For the same cooling-off period, the space required to store MOX is three times more than the one for UOX. The time frame generally considered for the spent fuel to be cooled sufficiently to allow handling varies from a few years (for instance, before reprocessing) to several decades before the spent fuel or vitrified waste

(1) Its exact value depends on the combustion rate.

from re-processing (which contain all the fission products and minor actinides contained in the spent fuel) is suitable before definitive disposal.

- ***Long-life radioactive decay***

Certain radioelements formed in the spent fuel are short or very short-lived waste. Most components of the spent fuel (uranium, plutonium, minor actinides and some fission products) on the contrary are long or very long-lived waste. The time frame for radioactive decay ranges from a few hundred to several hundreds of thousands of years and well exceeds the foreseeable future. This therefore demands that we conceive safe and stable storage solutions over a period of time no man-made structure can guarantee, hence the idea of using a natural structure that obeys a time scale fitting to the decay period of long-life radwaste and disposing of it in deep geological formations. Conversely, that time frame may result, on behalf of the future generations in, rejecting such an option and seeking other solutions such as advanced separation and the transmutation of minor actinides and long-life fission products and/or long-term interim storage (along the lines of research options 1 and 3 of the December 30th 1991 law) [1].

Although this would allow us in theory to recover the waste later, when transmutation technologies are sufficiently developed. This latter solution appears to be rather unrealistic, technically and above all economically, for category C wastes : these are currently conditioned in the most stable form possible (vitrification) to withstand natural chemical attacks and the effects of time.

- ***Degradation of nuclear energy sources***

This relates to the transformation of radioactive materials over time (the gradual disappearance of certain radionuclides and appearance of others according to a determined chain of events). It concerns all radioelements present in the spent fuel (whether present in the spent fuel or separated). The degradation of nuclear materials must be factored in when managing the back end of the fuel cycle, if it is decided not to dispose of the spent fuel directly. For instance, with the current reprocessing strategy aimed at separating and re-using the plutonium, the phenomenon of degradation of the plutonium isotope 241 due to the formation of americium 241 is very important : in just a few years, americium is formed in the separately stored plutonium in sufficient quantity [2] that the plutonium can no

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(1) See main excerpts from the December 30th 1991 law (referred to as the « Bataille » law) at the end of the glossary.

(2) Two phenomena occur : firstly, the americium isotope 241 is not fissile, whereas plutonium isotope 241 is, hence a reduction in the energy is likely to occur ; secondly,

longer be used directly for the manufacture of MOX fuel and requires a simplified reprocessing operation to remove the americium [1]. In future strategies aimed at re-using or « incinerating » some of the other materials contained in the fuel (minor actinides and long-life fission products), this problem would inevitably extend to all of these elements, therefore considerably increasing the complexity of management of the corresponding fuel cycle.

- ***Short-life radioactive decay***

This has little or no influence on the management of the spent fuel. It can, however, be of major importance for the dismantling of nuclear reactors. The residual radioactivity of these installations after evacuation of the nuclear materials, resulting from the irradiation of the structural materials, is due in large part to the short-life radioactive elements. The rapid radioactive decay of these elements assures a speedy reduction in the ambient radioactivity. To give an idea of the magnitude of the phenomenon, it can be estimated as a reduction by a factor of 100 in 30 years. This is the reason why we can consider postponing reactor dismantling operations after definitive shutdown.

The time factor must therefore be included in all decisions concerning the calendar, particularly at the back end of the nuclear cycle. For instance, if we decide to re-process, when should we do it? If deciding whether to dispose of spent fuels now or later, when do we dismantle the nuclear installations? Each decision will have huge repercussions on the economic cost of the different scenarios.

- ***Reprocessing now or later?***

Immediate reprocessing is necessary to separate out those materials that are suitable for re-use within a few years at most (as it is done today with plutonium). Immediate reprocessing involves having to handle the spent fuel while it is still very hot and separating the materials (particularly the plutonium) for interim storage. As we have chosen the option of not stockpiling plutonium in its separated form, it has to be used quickly. This poses the question whether it is appropriate to reprocess a spent fuel now, or later if we do not wish to recover any of its materials in the short-term, but might wish to re-cycle them later, in the medium or long-term.

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when the americium content in the plutonium exceeds a certain percentage, that plutonium is no longer authorised for use in the manufacture of MOX fuels.
(1) Removal of americium : separating the americium from the plutonium in order to be able to use the plutonium.

With deferred processing, however, the spent fuel can be handled after cooling and the materials wanted for recycling can be recovered in a directly usable, pure form. The formation of americium from a fissile isotope of the plutonium (Pu 241) however results in a progressive degradation of the energy content of the spent fuel.

- ***Disposal now or later?***

Long-term storage is a logical solution for materials present in spent fuels earmarked for re-processing (either to use their residual energy or reduce their volume or toxicity). It may, however, seem merely a way to postpone implementation of definitive disposal solutions for materials if it has been decided to evacuate (for instance, spent fuel in the open cycle without recycling option, or category B and C waste, in the reprocessing option). No country has yet implemented a definitive disposal solution, either for spent fuel or category C waste from civil electricity production. In reality, the long-term interim storage of such wastes can be explained by the advantage obtained in allowing them to cool down for several decades. That waiting period reduces the final costs of disposal and poses no particular technical, economical or safety problems. Interim storage of the spent fuel in a pool is needed initially, with the option of dry storage afterwards, for several decades or more.

- ***Dismantling now or later ?***

The introduction of a delay between definitive shutdown of an installation and the start of tear down operations significantly reduces the radiological impact of dismantling, especially for the personnel in charge of drainage and final dismantling operations. That waiting period, which has the additional advantage for the operator of deferring half of the costs, is the solution preferred by industry. Some operators envision a 50-year wait (standpoint of EDF) or even 100-year wait (standpoint of the British operators) before final dismantling. That solution however involves a risk (both in terms of safety and economics) due to lost memory of the installation. That is why the nuclear regulatory authorities in France particularly now ask the operator to examine in detail solutions for the immediate (20-year) dismantling for two prototype reactors : EL4 and Chooz-A.

The debate in fact basically concerns the reactors, where the radioactive « environment », after definitive shutdown, is principally due to materialactivating products that are short-life elements (i.e. with a radioactive period [1] of under 30 years, such as cobalt 60 whose radioactive period is five years). In the fuel cycle facilities, the absence of activation products and presence of long-life radionuclides (i.e. more than 30 years and sometimes as much as several hundreds of thousands of years) does not justify waiting. Immediate dismantling is therefore envisioned for enrichment and fuel manufacturing facilities and for the reprocessing plants.

In the analysis that follows, we do not take into account the possible influences on nuclear plant management of the level of electricity demand or emergence of technological progresses. Moreover, the possible interaction between the existing nuclear plants and those of the future will be analysed in the chapter on future facilities.

We will, however, when relevant, mention those points on which options taken up for the future fleet might affect the decisions to be taken on the existing nuclear plants.

2. Presentation of the current fleet of nuclear plants

Overall, the French fleet consists of relatively young and highly standardised nuclear plants. With the exception of Phoenix [2] it uses only one system : Pressurised Water Reactors (PWR) (réacteurs à eau pressurisée, or REP in French) and has only three reactor models corresponding to different development stages. The infrastructure development program has progressed rapidly in France : whereas the first two PWRs were commissioned in 1977, there are 58 today [3]. The cumulative total production by the entire fleet amounted to 5 486 TWh at end 1999, increasing from 1.1 TWh for 1977 to a total annual production of 350 to 400 TWh inclusively in recent years.

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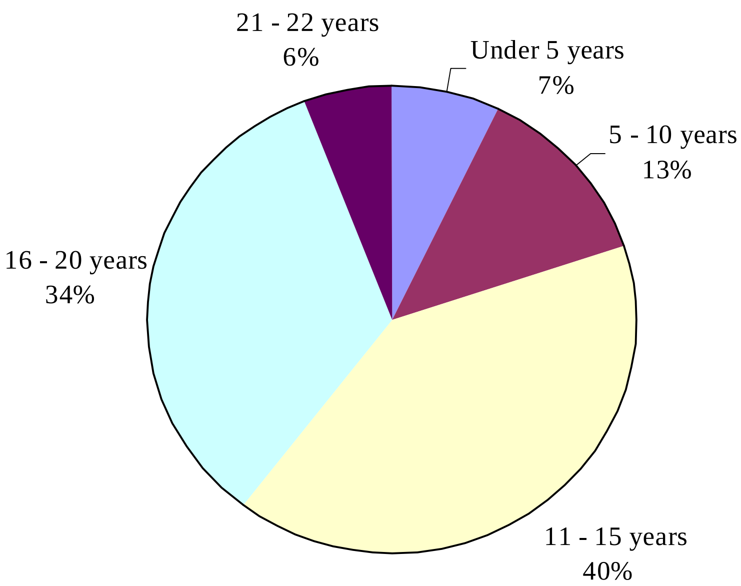
(1) See definition of « period » in the glossary.

(2) Although the Phoenix reactor, currently shut down, is theoretically capable of contributing to national energy production, its current status is that of a reactor dedicated for use in a research program : after the definitive shutdown of SuperPhoenix, the role of the Phoenix reactor, if operation resumes, will be to enable experiments on the incineration of actinides in rapid neutron reactors.

(3) The last one, Civaux 2, was connected to the grid at end 1999. However, as industrial commissioning of the N4 reactors has not yet been announced, France currently has 58 reactors connected to the grid, but only 54 in operation, in terms of being fully commissioned for industrial operation.

The 58 light water reactors connected to the grid are divided as follows : 34 reactors belonging to the 900 MWe stage varying in age from 11 to 22 years (average of 17 years) ; 20 reactors of the 1 300 MWe stage varying in age from 6 to 15 years (average of 11 years) and four N4 reactors of 1 450 MWe varying in age from 0 to 3 years.

Breakdown of electricity production capacity of nuclear plants, per age bracket, in France on January 1st, 1999



Source : CEA Elecnuc data

Building up of the French nuclear plants

During the 1950's, the Atomic Energy Commission (Commissariat à l'énergie atomique, CEA) developed a wholly French nuclear technology, the natural uranium graphite gas system (NUGG), and 9 reactors of that type with an overall gross capacity of 2 ,388 MWe were connected to the grid between 1956 and 1972 : those reactors were loaded with natural uranium in the form of metal ; they were moderated with graphite using compressed carbon dioxide (at 30 bar, 400°C) as the coolant. The first three NUGG reactors were operated by the CEA with the aim of producing nuclear material for military uses, the six other reactors were operated by EDF.

Over the period 1968 to 1994, all of those reactors have been disconnected from the grid : six are currently being dismantled [1] (five in level 2, one in level 1) and definitive shutdown is in progress for the remaining three.

That fleet of NUGG units produced a total 13,000 tonnes of spent fuel (most of which was reprocessed either at the Marcoule UP1 facility, or at the La Hague facility) for a total electricity production of 227 TWh – working out at an average combustion rate of 2.5 GWj/t.

The PEON Commission (the consultative commission for electricity production using nuclear energy) was set up in 1955 to evaluate the costs involved in the construction of new nuclear units. In view of the poor competition of the NUGG reactors compared with the economics of the PWR system, and the difficulties encountered in obtaining a power of more than 500 MWe, the PEON Commission voted in favour of the construction, of 4 to 5 light water reactors over the period 1970 to 1975 with a unit power of 900 MWe.

The programme picked up speed in March 1974 when Pierre Messmer's government adopted a two-year plan to implement sixteen new light water units of 900 MWe. Efforts continued in 1975 with a commitment for 1976 and 1977 to a 12,000 MWe programme before a skip to a higher stage (1 300 MWe). It was estimated at that time that a further 12 900 MWe capacity will be needed to meet the demand for electricity in France. In 1977, the rate of construction slowed again to 5,000 MWe for the next

(1) Strict terms govern the shutdown of installations: definitive shutdown of production is followed one year later by the definitive cessation of operations, then three years later by preparation for dismantling (MAD level 1) and lastly by carrying out the dismantling process (MAD level 2 then 3) over 56 years, a 40-year storage period being considered between MAD2 and MAD3. The dismantling levels defined by the IAEA differ particularly in the degree of monitoring required: level 1 corresponds to monitored shutdown (nuclear materials confined to the nuclear core); level 2 the partial release of the site (reduction of the containment areas); level 3 its complete release.

two years. In the early 1980's there were 18 reactors in operation and 33 under construction. The program was pursued over the entire decade of the eighties, however forecasts of a slow down in growth of the electricity demand resulted in the program being cut back in 1985, though it reached the higher power stage of 1,450 MWe per reactor.

We should also mention the first pressurised water reactor in France (Chooz A), the EL4 reactor, a prototype of the heavy water and natural uranium reactor, and SuperPhoenix the sodium reactor, all of which are now no longer in operation.

3. Materials balance and economic balance associated with the current fleet of nuclear plants

3.1. Methodology

To evaluate the consequences of past choices and implications of the various options for the future, we sought to describe as clearly as possible the materials balance and economic balance for each of the options. To achieve that, we chose to collate past data and describe possible scenarios arising out of the current situation and the options available for management of the nuclear plants and fuel cycle. That description has been made with sufficient accuracy to enable us, in a first step, to calculate the annual flow of materials. Then those material flows were used, in the second step, to evaluate the associated annual economic flow based on unit costs supplied by the operators (or estimated costs when the relevant information was lacking).

Choice of scenarios

The choice of variables used to differentiate between scenarios was guided by the determination to outline a few realistic options, without unnecessarily multiplying the number of forecasts. We thus distinguished between scenarios, using two criteria whose impact on the materials balance and economic balance of the existing fleet and the future fleet of nuclear plants we considered to be of particular importance :

- ***Firstly, the service life of the nuclear plants :*** Operating the power plants for several years over and above the anticipated service life increases the materials balance and alters the economic balance by increasing production and expenditure on upkeep in a way that may or may no longer be favourable. Above all, extending the service life of the power plants impacts the availability of future options for the facilities : the longer the current capacity can be kept going, the longer it will be before new reactors need to be built, which works in favour of technological innovation and therefore the availability of alternatives to the pressurised water reactors currently used to replace the obsolete plants.

We selected two major hypotheses for the average service life of the power plants, 41 and 45 years. This 10 % variation may seem slight compared to the spans usually practised (from the minimum 30-year lifetime to the 50 or 60-year value anticipated by the operator when the reactors were first designed). In fact, those two values reflect differences in reactor ageing (the average of 41 years reflects lifetimes of 35 to 45 years, the average of 45 years reflects lifetimes of 35 to 50 years). The four-year differential accounts for the impact of this parameter on the balance of materials and on the economic balance.

Service life of the current nuclear plants

Two main elements condition the technical service life of a nuclear plant : the core of the reactor and the reactor containment building. The other equipment can if necessary be changed, depending on their ageing, obsolescence or the mandates of the nuclear safety authorities. The expenses incurred to keep the nuclear plants running are considered as upkeep.

The clauses contained in the definitive safety reports on the 900 and 1300 MWe reactors recommend that the maximum duration of irradiation be 40 years at 80 % of nominal power in the initial conditions of fuel loading, i.e. the equivalent of 32 years at full power. That recommendation is without prejudice to the result of periodical inspections or specific requests made by the safety authorities. Following that recommendation would result in a gross cumulative electricity production by French nuclear plants of 18,250 TWh. That accumulated production is compatible with the first chosen hypothesis of an average service life of 41 years for the fleet and a hypothesis of a continuing improvement in the production rate of the nuclear plants (rising from 70 % in 2000 to 85 % in 2032).

However, various parameters are likely to impact the lifetime of the plants in a positive manner. Those parameters include :

- the implementation of so-called “low leakage” fuel loading plans, intended to reduce the flow of neutrons inside the vessel and consequently, for the same maximum flow value at the internal wall of the vessel, to increase the lifetime beyond 32 years at full power. The operator hopes to be able to implement those new loading plans sometime during this decade ;

- the possibility of carrying out heat treatment on the reactor vessel. This kind of treatment has already been performed on 12 reactors of soviet design and on some propulsion reactors belonging to the American navy, under an R&D program on PWR reactors being conducted in the United States.

The hypothesis of better combustion rates for the fuels in use by the year 2010 that we selected for our various scenarios in line with EDF and Framatome forecasts leads to the manufacture of new fuels. By reducing fluence on the inside wall of the vessel, those new fuels result in a longer service life.

Given the age distribution of the reactors when those new fuels will be brought into use, a 20 % reduction in fluence should be obtained, enabling a concomitant 10 % increase in the reactor service life up to approximately 45 years.

By choosing 45 years as the average lifetime, we allow margin for possible improvements, assuming the vessel receives heat treatment when it reaches approximately 35 years of age. That explains why some nuclear plant operators anticipate lifetimes in excess of 50 years for their existing reactors of similar technology to that of the French fleet.

- ***The second is the strategy for the back end of the cycle*** : the many strategies possible can be divided into two main options : reprocessing the spent fuel and recycling the recovered materials (plutonium in this case) or the open cycle assuming interim storage then the direct disposal of the spent fuel. The choice of one of the two options will have repercussions on the entire cycle, from front-end (savings in raw materials) through to the back-end of the cycle (quantitative and above all qualitative balance of the waste materials).

France’s chosen strategy at present is the « reprocessing-recycling » of UOX fuel, during which the plutonium is recycled once only in the form of MOX fuel. Some of the UOX fuel is, however, temporarily at least managed in open cycle, since it is placed in interim storage and not reprocessed immediately.

The three hypotheses we have imagined for the back end of the cycle are :

- continuing with current situation and maintaining reprocessing within a proportion of 65 to 75 % inclusively of the spent UOX fuel and using MOX in approximately 20 reactors (the 20 reactors of the 900 MWe stage currently authorised to load MOX) ;

- extending reprocessing to all unloaded UOX fuel, which corresponds to using MOX in 28 reactors (the 28 reactors of the 900 MWe stage that are technically capable of burning MOX) ;

- abandoning reprocessing altogether and switching to an open cycle strategy. We preferred a progressive abandonment scenario rather than one with a sudden change [1], which would raise many technical obstacles (storage of the spent fuel) as well as legal and social problems. In this scenario, reprocessing stops in 2010. MOX would continue to be used at the current level for 2 to 3 years after 2010 in order to use up the stock of separated plutonium.

Purpose and advantage of reprocessing [2]

Reprocessing has two goals. It aims first at separating those substances in the spent fuel that possess real or potential energy-related value (i.e. uranium and plutonium) and second at conditioning the ultimate waste (fission products and minor actinides) in a form suitable for several thousand-years “permanent” storage. Using the vitrification process, radiological waste is incorporated by melting into a glass, which is certain to retain the radioactive substances because of the chemical combination of its constituent parts).

Reprocessing enables more than 99.8 % of the plutonium content to be extracted from the spent fuels. Although plutonium accounts for only approximately 1 % of the spent fuel, it is accountable for nearly 90 % of the overall radiological toxicity of the spent fuel after 100,000 years. This is why it is desirable to reduce the plutonium for definitive storage as much as possible. This is the reason why the extraction rate of plutonium from the spent fuel is so high, and thus does not correspond to the economic optimum. The result of the actions undertaken by the law passed on December 30th, 1991 relative to research on long-life radioactive waste management will enable confirmation of the conservative rate we work to at the present time. Plutonium is now recycled as a MOX fuel. Recycling significantly slows the overall quantity of plutonium produced each year in French NPP’s. Indeed, a reactor whose core consists of 30 % of MOX assemblies and 70 % of standard fuel assemblies using enriched uranium oxide does not produce plutonium, whereas a reactor composed of 100 % of standard fuel assemblies produces approximately 200 kg a year. Moreover, reprocessing, as any industrial activity, generates waste and releases.

(1) We have also considered in “Le parc nucléaire actuel”, a scenario in which reprocessing is abandoned in 2001, the scheduled date when the reprocessing contracts signed between EDF and Cogema come up for renewal.
(2) Excerpts from « 110 Questions on Nuclear Energy », published by the French General Directorate for Energy and Raw Materials.

As with any other nuclear facility, these liquid and gaseous releases and waste from reprocessing units are governed by limits set by the safety and radioprotection authorities. The authorised limits do not, however, constitute thresholds beyond which health is jeopardised. The environment of the La Hague reprocessing plant is particularly stringently monitored by the radioprotection authority. The controls and surveys performed around the La Hague site have revealed no evidence of an impact on health.

Reprocessing also generates solid waste. During plant operation, the quantity of long-life waste generated by the reprocessing operations carried out by COGEMA currently represents nearly 1 cubic metre per ton of re-processed fuel, whereas direct storage would generate 2 cubic meters of waste per ton of spent fuel. By the year 2000, COGEMA's objective is to bring that volume down to 0.3 to 0.5 m^3 per ton of re-processed fuel. Last, the dismantling of reprocessing facilities will generate significant volumes of waste, the majority of which will be only slightly radioactive. Anyhow, the overall radioactivity of that waste will be far below that which would result from the direct storage of the spent fuel. A definitive method of disposal for these low activity wastes, on a design similar to that of a conventional dump yet specific to this type of waste, is currently being studied.

By cross-matching the different hypotheses, we obtain the following six scenarios :

	Average service life 41 years	Average service life 45 years
Reprocessing stops in 2010	**S1**	**S4**
Partial reprocessing 20 MOX units	**S2**	**S5**
100 % reprocessing 28 MOX units	**S3**	**S6**

Aside of those scenarios, a seventh scenario is detailed in the annex. It is based on the hypothesis of the total absence of reprocessing (i.e. with no investments in the La Hague reprocessing facility or in the MOX manufacturing facility) and enables a better grasp of the difference between balances with and without reprocessing.

A few hypotheses are common to all scenarios for the current set of nuclear power plants, such as no reprocessing of MOX, no recycling of the depleted uranium obtained from the reprocessed UOX (URT)[13], the period of interim storage prior to disposal in deep storages (which is the chosen solution in every scenario for the evacuation of medium and long-life high-level radioactive waste).

A few more hypotheses were selected, i.e. :

- on fuel performance : we assumed an improvement in the combustion rates, whether for UOX or MOX up to a ceiling of 55 GWj/t for UOX and 49 GWj/t for MOX (average values). For comparison purposes, the maximum allowed values are currently 52 GWj/t for UOX and 41 GWj/t for MOX ;
- on nuclear plant performances : currently they are handicapped in France by over-capacity of the electricity production. The capacity factor (Kp) of the nuclear plants is low compared with the Kp achieved by nuclear plants in other countries. In our scenarios therefore, we hypothesised a gradual re-absorption of that over-capacity, enabling a favourable evolution of Kp, from 70 % now to 85 % by the year 2030 ;
- on the recycling of URT (uranium obtained from the reprocessing of UOX) : we opted for interim storage of URT in anticipation of more favourable economic conditions for possible recycling later ;
- on leaving Eurodif, the depleted uranium is transformed into U_3O_8 and placed in long-term storage in Bessines where a storage facility of 200 000 tonnes capacity has been in operation since 1998) ;
- on the shutdown procedure for the nuclear facilities of the fuel cycle, except in scenarios S1 and S4 where reprocessing stops in 2010 and recycling is phased out in 2012-2013, we considered that a full industrial tool (reprocessing + recycling) can no longer be maintained once the annual need for reprocessing drops below 500 tonnes and/or the annual need for MOX drops below 50 tonnes. Clearly, in this respect, however, no decision on shutdown can be taken in the light of the current reactor fleet alone, ignoring the future fleet ;
- on the dismantling of the nuclear installations, we opted for immediate dismantling of all nuclear installations belonging to the fuel cycle, and dismantling in two stages for nuclear reactors (having already calculated the cost of the alternative : dismantling in a single phase).

The material balance of the fleet (front-end and back-end of cycle)

The objective here is to explain in detail the evolution of the physical flows relating to the electricity production, fuel cycle and total waste generated by the fleet of nuclear plants over their lifetime. What we refer to as nuclear waste are « those substances abandoned on completion of the nuclear cycle, an abandonment that may only be transient since it depends on the technical and economic conditions at the time ». The materials balance takes into account :

- **at the front-end**, those elements needed to manufacture the loaded fuel, namely :
  - natural uranium (U_3O_8) ;
  - those needed for conversion (from U_3O_8 to UF_6) ;
  - those needed for enrichment, expressed in separation work units (SWU) ;
  - those needed to manufacture the UOX assemblies ;

- **at the back-end**, those elements resulting from the processing of the unloaded fuel, categorised according to their life and activity level, i.e. :
  - reprocessed UOX and nuclear materials separated during reprocessing, i.e. reprocessed uranium (URT) and above all plutonium ;
  - materials required to manufacture MOX assemblies ;
  - depleted uranium obtained from enrichment which is converted either for use in the MOX or for long-term storage ;
  - non-reprocessed spent UOX and MOX ;
  - category B waste produced by reactor operations and category B waste from reprocessing ;
  - category C (vitrified) waste resulting from reprocessing.

The radioactive waste categories used in our report

Two main criteria are taken into account when categorising waste for management purposes :

- firstly the life time of the waste, calculated on the period of the radioactive products contained in the package used to define the duration of potential toxicity of the waste. Waste is generally categorised as short- or long-life, according to whether their "period" is under or over 30 years [1] ;

(1) The existence of such a « period » is related to a fundamental property of radioactive decay: the period of the wastes refers to the time needed to reduce their radioactivity by half. It depends on the radionuclides present in the waste packages : each of them has a characteristic, fixed period or life during which its quantity,

- secondly, their activity level, i.e. the intensity of radiation produced by the package. This factor determines the protective measures needed in order to define the appropriate method of storage. The waste is distinguished according to the different activity thresholds (alpha, beta and gamma radiation) into very low level, low-level, medium-level or high-level waste.

By cross-matching these two criteria, we obtain eight categories of waste, the main ones – those corresponding to the largest quantities of waste produced by the nuclear industry – being grouped as :

- minor residues, i.e. materials produced in large quantities by the extraction of uranium ore ;
- very low-level radioactive waste, essentially produced during the dismantling of nuclear installations. This category particularly covers construction materials used in potentially contaminated areas during the active phase of the installations (reinforcing steels and other debris). Their radioactivity amounts to approximately a few becquerels per gram, however the pose a specific storage problem because of the large volumes involved ;
- short-life low- and medium-level waste (category A waste), characterised by an activity due principally to beta and gamma radiation. Nuclear reactors, spent fuel processing facilities, nuclear research centres particularly produce this category of waste, consisting mainly of waste from manufacture, used equipment and materials and also the products of nuclear installations liquid and gaseous effluents treatment ;
- long-life medium-level waste (category B) which in particular contains a significant quantity of products that emit alpha radiation and have a low thermal output. These products derive mainly from the maintenance and operation of the reprocessing facilities. Because of its very long life, this waste requires very long-term disposal solutions ;
- short or long-life high level waste (category C) containing large quantities of alpha radiation emitters characterised by a high thermal output. They generally contain a mix of highly radioactive short-period elements and low or medium-level radioactive elements of long period. Category C waste generally consists of fission and activation products (plutonium and minor actinides) contained in the spent fuels (products that will eventually be recovered when reprocessing those fuels). Management of this category of waste poses problems in terms of length of storage. Research into categories

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whatever that may be, is halved. The period of radionuclides can vary from a time of under one-second to a time of over a billion years.

B and C waste are being conducted within the framework of the law on waste management passed on December 30th 1991 [1] ;

- non-reprocessed spent fuels : this may include spent UOX, if not considered for reprocessing, or spent MOX. These spent fuels contain highly active long-life products (plutonium, minor actinides, and fission products). They require long-term storage (50 years for UOX, 150 years for MOX) until their thermal output has cooled sufficiently to allow definitive disposal.

In presenting that balance of materials, we are particularly seeking to compare scenarios in terms of the final plutonium balance (plus the existing americium continually formed in the plutonium from its isotope 241). The plutonium balance is of specific interest inasmuch as French research and development efforts for the management of the back end of the cycle are based, initially, on the determination to leave no plutonium in definitive disposal, (because of its long life and much higher radiotoxicity than that of the other radioactive products stored and/or because of its high potential as a source of energy). Thus, the impact of the plutonium balance is classically presented as one of the main advantages [2] of the “reprocessing-recycle” strategy over direct disposal.

The balance of materials results from the interaction of many and continually changing parameters. Those parameters principally affect :

- fuel cycle management options that impact the front end of the cycle and fuel quality (e.g. the materials used and the enrichment rate) and the back end of the cycle and the share-out of materials (reprocessing-recycle or direct disposal, waste characteristics) ;
- the characteristics of the industrial processes implemented (reject rate, volume of waste per production unit, performance of the reactor steam supply system, etc.) ;
- the quality of nuclear fleet operation, whether as regards the fuel (combustion rate, management of the combustion cycle) or the reactors, (availability, scheduled outages, etc.) ;
- management of the fuel cycle calendar (cooling period, particularly between different stages of the cycle, even before the last stages of the cycle) and of

(1) See end of glossary for the main elements of that law.
(2) See box in chapter 2, on the respective advantages of reprocessing and direct disposal.

the nuclear plants themselves (lifetime of the plants, dismantling now or later).

Based on the parameters associated with the different possible evolutions of the nuclear fleet, we calculated the corresponding balances of materials.

Economic balances

The economic balances are calculated from the material balances. We use them to calculate or verify the consistency of results based on the information in our possession on unit costs of production, operation, interim storage, disposal, etc. Then, based on the annual physical flows, we evaluate the economic flows corresponding to the necessary exchanges of materials and services.

The exercise was divided into two periods :

- ***The past (1977 – 1999),*** 1977 being the year the first pressurised water reactors (PWR) [1] were commissioned. Over that period, we have been able to establish a balance of material flows using real historical data on the fleet and the fuel cycle ; the balance obtained therefore represents a fairly accurate estimate of real past results, although it cannot be an absolutely true reflection. In particular, the fluctuations in some of the parameters were levelised and some marginal operations were left out. Similarly, we were able to reconstitute the history of expenditure associated with the development of the nuclear plants over the period. Those itemized details of expenditure over time enabled us to establish an overall economic balance of the cost of the existing fleet over the entire period from their launching until now.

- ***The future period, from now to the end of the lifetime of the existing nuclear fleet***. We sought to calculate the balance of materials for the six scenarios described earlier. Although only two variables are used to differentiate between the scenarios in our definition, this does not necessarily mean that all other parameters were fixed : the scenarios forecast changes in some parameters, for instance the gradual increase in capacity factor or combustion rates, however these parameters are identicals in all of the scenarios.

(1) With the exception of Chooz A PWR prototype, commissioned in 1967.

- The legacy from the past for France -

To simulate the costs associated with the existing fleet in the different scenarios for the future period, we reconstituted the annual history of expenditure item by item, based on informations supplied to us, whenever possible by the operators themselves, concerning the unit costs of the different services or materials.

3.2. Critical examination of the selected hypotheses

The hypotheses we selected for the combustion rate or capacity factor are subject to uncertainty. They reflect improvements that may never happen. Failure to meet those targeted improvements may weigh heavily on the material balances and the corresponding economic balances :

- *Concerning the evolution of the capacity factor*, we studied the influence of a faster or slower variation, leading in the former case to a capacity factor of 85 % in 2020 (instead of 2030) and in the latter case to a capacity factor of 81 % at the end of the lifetime of the current power plants. For scenario S6 for instance, those new hypotheses regarding the Kp would result in a gap in cumulative production between now and 2050 of 6.3 % (- 4 % to + 2.3 % below or above the reference situation). In fact, the evolution of the capacity factor will depend primarily on how long it takes EDF to reabsorb its over-capacity for base-load production (as the fleet of plants is designed to supply the maximum power demand) which in turn will depend heavily on the evolution of the electricity sector [1] in Europe ;

- *Concerning the evolution of combustion rates*, the main stake bears on the ability of the MOX to achieve the envisioned values. That factor for MOX figures essentially in scenarios S2, S3, S5 and S6 in the hypothesised increase in the combustion rate up to 49 GWj/t. According to EDF, that economic condition is necessary if they are to continue the long-term use of MOX. In the case of UOX assemblies, some nuclear plant operators have already achieved the proposed values.

The other hypotheses are generally favourable too (although from time to time we introduced a few damaging hypotheses). Indeed, all scenarios are based on

(1) We can particularly envision an electrical organisation in which the use of the fleet of power plants would be optimised at European level. The operators would, for instance, organise « swaps » so that nuclear power would be used for the base-load, which would enable a favourable evolution of the production capacity in the nuclear reactors.

an optimum management of the nuclear plants and fuel cycle (for a given strategy), without setbacks or industrial problems. For instance, the La Hague facility is shut down when reprocessing needs fall below a certain threshold or when the facility becomes unprofitable ; the combustion rates are increased with ease ; the new interim storage facilities are designed of the ideal size ; all category B wastes can be compacted and conditioned in an appropriate manner ; MOX manufacturing rejects are fully recycled ; cooling and storage periods between stages are always ideal (never excessive) etc. These examples may make our forecasts seem optimistic in the light of experience gained over the period 1977-1999, however we got now the benefit of hindsight and feedback on the installations, most of which are still in operation today.

The impact on the material balances is evident. For instance, we adjusted the scenarios so that there would be no leftover stock of separated plutonium. Similarly, some of the hypotheses on costs are optimistic : for instance, the cost of reprocessing used for the La Hague facilities is the cost when running at full capacity.

3.3. Material balances associated with the scenarios

We calculated the balance of materials on a yearly basis for each of the selected scenarios. The heading of "waste" comprises not only ultimate waste (categories B and C) but all spent fuels in interim storage awaiting a decision on possible later recycling.

For the back end of the cycle, we hypothesised that :

- the different spent fuels will either be reprocessed to recover the re-usable uranium and plutonium content, or packaged and sent for definitive disposal ;
- category B waste from reactor operations and category B waste from reprocessing operations will be stored and conditioned prior to definitive disposal ;
- category C waste will be packaged in glass molds essentially containing fission products and minor actinides (actinides other than uranium and plutonium).

Finally, we hypothesised that a storage centre for very low level waste will be available some time between 2005-2010, a definitive disposal facility will be in place for category B waste by 2020 and a definitive solution will be ready for the disposal of category C waste by 2040-2050.

The installations necessary for the interim storage and definitive disposal of spent fuels will be envisioned as appropriate to each of the scenarios. The chosen solution will take into account the intended use for the plutonium contained in the spent fuels. In the long term, after depletion of the conventional fissile resources, use of that plutonium may be justified. This poses the problem of the reversibility of the definitive disposal solution. A reversible solution is much more advantageous in that it allows room for a U-turn in the event of a major problem, for instance, recovery of the stored elements in the event of significant water infiltration, or recovery of materials not necessarily for re-use but for elimination if transmutation-incineration solutions are found at a later point in time.

Balance of materials in 2050 in the different scenarios

	Average lifetime					
	41 years			45 years		
Electricity production in TWh	18 111			20 238		
Needs	**S1**	**S2**	**S3**	**S4**	**S5**	**S6**
Natural uranium in thousands of tonnes (Kt)	415	407	398	460	447	437
Enrichment in MUTS	297	290	284	330	321	313
UOX manufacture in kt	52	51	50	56	55	54
MOX manufacture in kt	2.0	3.0	4.1	2.0	3.5	4.8
UOX reprocessing in kt	15.0	22.4	31.1	15.0	26.2	36.1
Spent fuel storage needs in kt	25-30	15-30	5-20	30-45	20-35	10-25
Storage/Disposal	**S1**	**S2**	**S3**	**S4**	**S5**	**S6**
Depleted uranium in kt	361	353	344	401	389	379
URT from PWR in kt	14.3	21.4	29.5	14.3	24.8	34.1
UOX fuels in kt	36.2	28.0	18.4	41.0	28.6	17.6
MOX fuel in kt	2.0	3.0	4.1	2.0	3.5	4.8
Stock of non-separated Pu+Am in t	542	512	476	602	555	514
In cubic metre category B waste (reprocessing)	11,786	13,811	16,564	11,786	14 ,825	18, 091
In cubic metre category B waste (operation)	20, 000					
In cubic metre category C waste (vitrified)	1,600	2,695	3,974	1,601	3,325	4,808

Source : Working group on the « Existing Fleet of Nuclear Plants »

We draw a number of conclusions based on, the cumulative materials balance up until 2050, prepared from the annual balances :

- ***Front end***

The materials balance provides information on needs for uranium, units of enrichment and UOX fuels. We note that the differentiation between the scenarios has no major repercussions on the front end of the nuclear fuel cycle. The cumulative needs for natural uranium vary by 5 % between scenarios where reprocessing stops in 2010 and scenarios with 28 units running on MOX fuel.

The period 2020-2030 should correspond to the shutdown of the current enrichment plant run by Eurodif : if the date is 2020, the current fleet of nuclear plants will need an additional 57 to 92 MUTS (6 to 9 years production with Eurodif running at maximum capacity) ; if 2030, the additional needs would be between 15 and 32 MUTS inclusively (2 to 3 years production by Eurodif at maximum capacity). Ten years before shutting down Eurodif therefore, decisions will have to be made on the enrichment technology option or whether to purchase UTS on the international market [1], however those decisions will also depend on the needs of the future power plants.

Concerning the *fuel manufacturing capacity*, the annual needs for UOX remain in excess of 800 tonnes up to around 2025. If the nuclear fuel manufactories run by FBFC (Romans, Dessel) the joint French/Belgian company act satisfactorily, they will not need replacing before that date ; as for MOX, the capacity of the Melox and Dessel will be sufficient to meet the needs except in scenario S6 (a service life of 45 years and 28 units running on MOX) where it would be necessary to increase the capacity of the Melox facility to manufacture MOX fuel for use in PWRs. Conversely, scenarios S1 and S4 assume shutting down the Melox factory after 2010.

- ***Back end***

More options are open to choice as regards the back end of the cycle, where the avenues of choice are more distinctive and also the physical and economic uncertainties are greater.

Options for the back end of the cycle (reprocessing + MOX or open cycle) have a diversity of consequences on the nature and quantities of wastes to be stored for the short and the long-term.

For several years, EDF has been committed to the reprocessing of its spent fuel, however? to avoid building up stocks of separated plutonium for which no use can be found, EDF reprocesses only when it has outlets for the plutonium that is produced.

For each individual scenario, the materials balance provides information on needs for MOX [2], on the cumulative waste (in terms of both quantity and

(1) In both cases, when preparing the economic balances, we will not take into account the initial investment in the enrichment plant, as this is included in the price of the UTS.
(2) We should recall that the use of MOX enables reducing the need for fuels for if six UOX assemblies have to be reprocessed to obtain the necessary Pu to manufacture a MOX assembly, then that MOX assembly can replace a UOX assembly in a « MOX » reactor (i.e. able to burn up to 30 % of MOX).

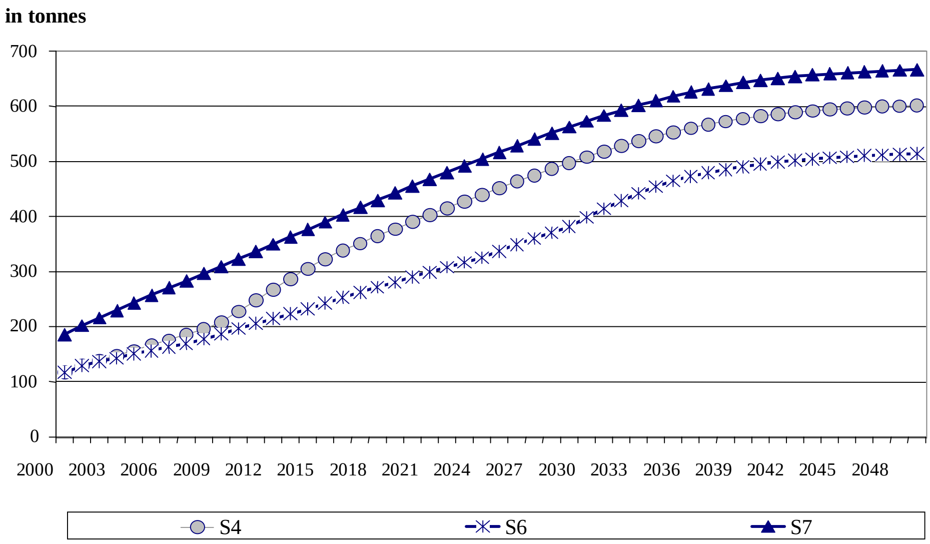
quality), on storage capacity needs for spent fuels and other recyclable materials, on reprocessing-recycling needs and on definitive disposal conditions for certain types of waste. There is a strong differentiation between the cumulative needs for MOX between the scenarios (from 2 kt in S4 to 4.8 in S6). We will look with particular interest here at the waste directly related to management of the back end of the fuel cycle, that is category B waste (long-life waste of medium radioactivity) and C (long-life highly radioactive waste) resulting from the reprocessing of UOX fuels and, inasmuch as they are not reprocessed immediately, of spent UOX and MOX fuels. The other waste produced by the nuclear industry (very low-level waste, category A and category B waste from operations) result in approximately similar balances in the difference scenarios for the back end of the cycle.

Plutonium + Americium content of non-reprocessed spent fuels

Concerning the stock of non-separated plutonium and americium contained in the stored spent fuels, the differences between the various scenarios are fairly insignificant. That stock would culminate at 602 tonnes in S4 (service life of 45 years and reprocessing ceased in 2010) [1], compared to 514 tonnes in S6 (service life of 45 years and 28 units running on MOX). Scenario S6 therefore results in 15 % smaller stock of non-separated Plutonium + americium, as shown in the following graph.

(1) It would have reached 667 tonnes in case study S7, the scenario in which there would have been no reprocessing over the lifetime of the existing fleet. See annex for a presentation of scenario S7.

Stock of Pu + Am



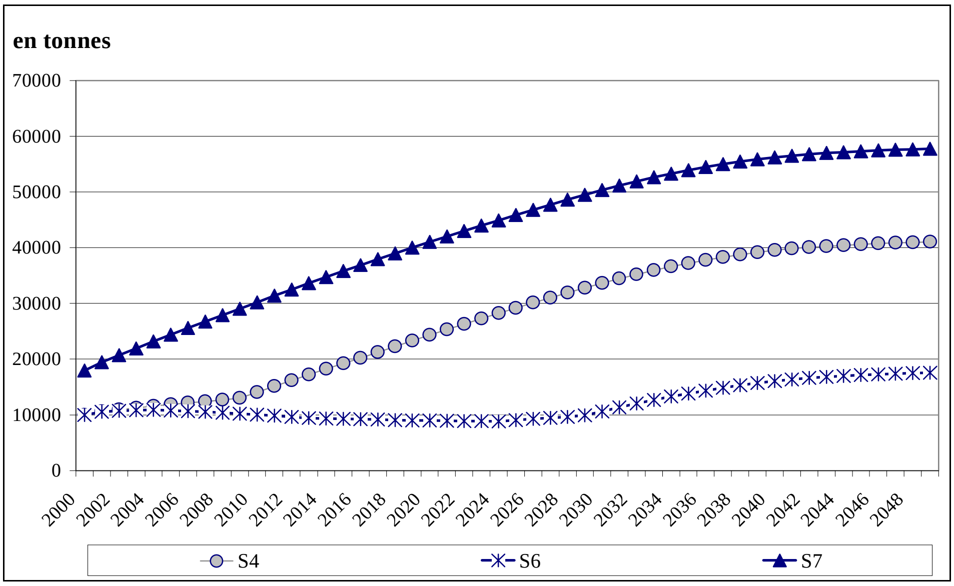
Source : Working group on the « Existing Fleet of Nuclear Plants »

However, that small difference masks a significant diversity in the nature and quantity of the spent fuels for short- and long-term storage in each of the scenarios (cf. the 2 following graphs).

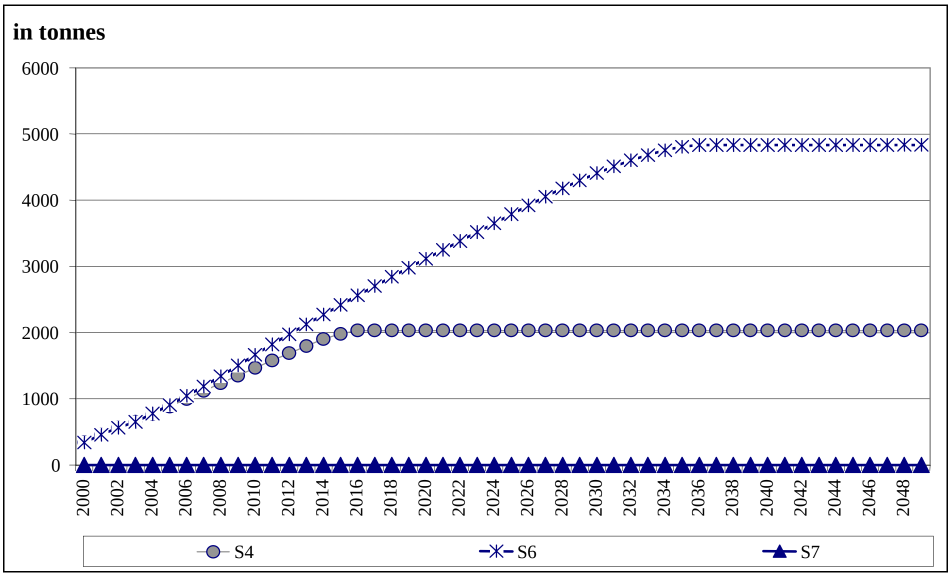
Thus, in scenario S4 for instance, the one in which reprocessing is ceased, it would be necessary to store 41,000 tonnes of UOX whereas in scenario S6, only as third the quantity (17,600 tonnes) needs to be stored.

However, in S4, only 2,000 tonnes of spent MOX needs to be stored, compared to 2.4 times more (4,800 tonnes) in scenario S6.

Spent UOX stock



Spent MOX requiring storage



Source : Working group on the « Existing Fleet of Nuclear Plants »

In fact, between those scenarios, we note transfer phenomena operating between the different categories of waste, which makes it difficult to compare the different strategies.

Between the scenarios of continuing or ceasing to reprocess, we however see a slight reduction in the cumulative stock of plutonium or uranium, a slight reduction in the cumulative thermal output and a big cumulative reduction in the volume (or total tonnage) of highly radioactive long-life waste.

This therefore reveals a transfer : reprocessing plus recycling of the plutonium in MOX concentrates the activity and thermal output into a less volume ; on the other hand, it leads to considerably longer times for cooling the MOX fuels prior to definitive storage.

Waste in categories B and C

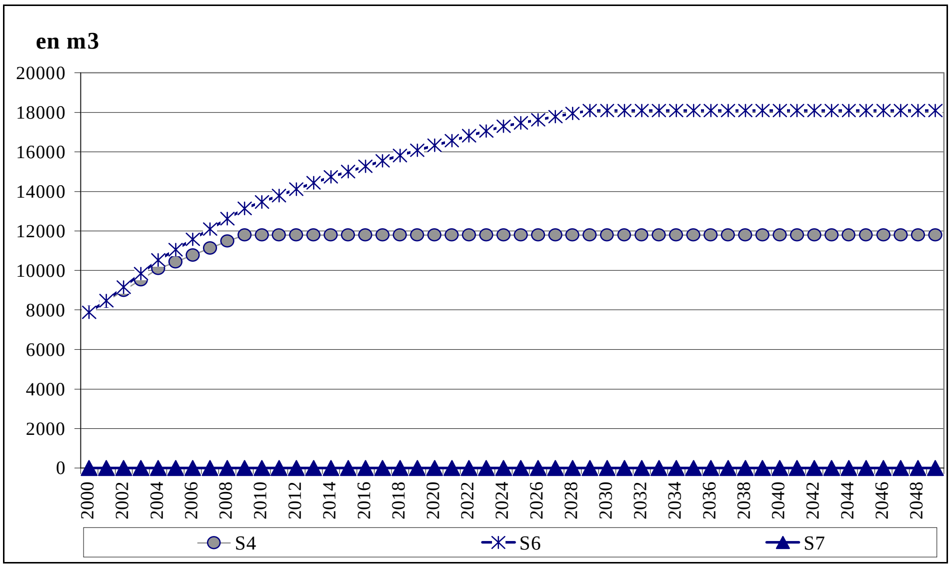
Here again, the final situations are totally different.

Category B waste

As the material balances show, the volume of ***category B waste*** produced during operation of the reactors (20, 000 m^3 between now and the end of the service life of the current power plants, including the older ones) is the same in all scenarios. Opening the operation of the storage centre somewhere around 2020 would enable the evacuation of those wastes at the time of the definitive shutdown of the first reactors, without requiring any intermediate storage capacity.

As for the category B waste produced during reprocessing operations, they fluctuate, as illustrated in the following graph, from 11,800 m^3 in scenario S4 (reprocessing ceased in 2010) to 18,000 m^3 in S6, on condition that the compacting installation scheduled to start up in 2000 achieves the anticipated performances.

Stock of category B waste
(except for category B waste produced in the reactors)



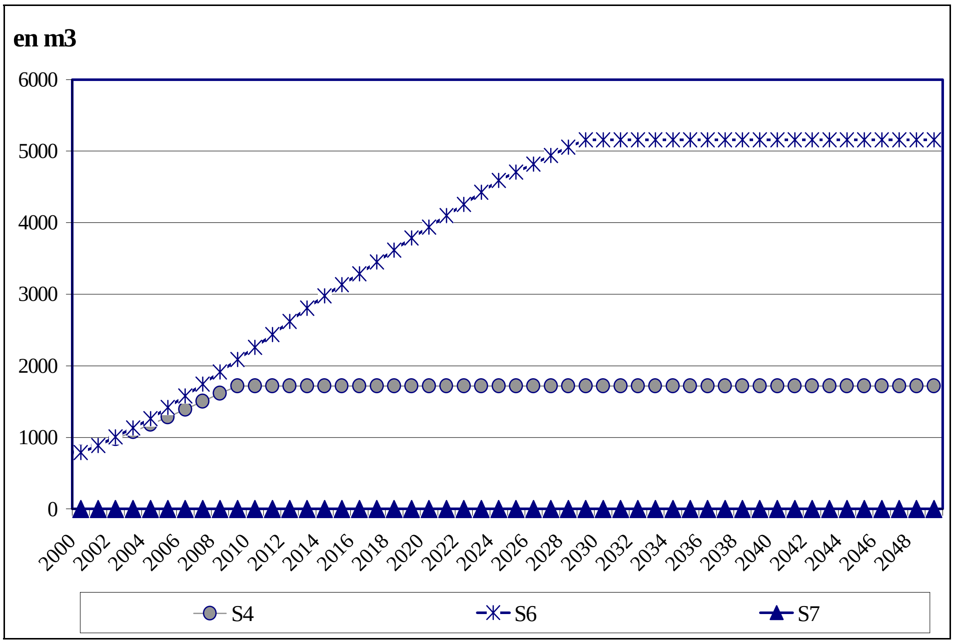
Source : Working group on the « Existing Fleet of Nuclear Plants »

Category C waste

Category C waste produced by the vitrification operations used as solutions for the fission products and minor actinides produced by the reprocessing operations are conditioned immediately into containers.

Their accumulated volume for the power plants in operation today amounts to 4,800 m^3 in scenario S6, yet is three times less (1,600 m^3) in scenario S4 (see following graph).

Stocks of category C waste



Source : Working group on the « Existing Fleet of Nuclear Plants »

Depleted uranium and uranium from reprocessing

Depleted uranium is the residue of the natural uranium after enrichment. The depleted uranium still contains approximately on third of the natural content of uranium 235. It is therefore likely in the long-term to constitute a low content resource of uranium 235.

The stock of depleted uranium reduces only very slowly, at the same rate as the needs for natural uranium in the different scenarios. It reduces from 400,000 tonnes (S4) to 380,000 tonnes (S6) between now and 2050.

The uranium from reprocessing (URT) obtained from the reprocessing of UOX that has only been spent once in the reactors, has identical properties to that of uranium ore and can therefore (subject to certain conditions [1]) constitute a fuel resource for the French PWRs. The stock of this kind of uranium, contrary to

(1) In particular it requires a slightly higher enrichment to compensate for the presence of isotopes other than uranium isotopes 235 and 238.

the previous kind, sees a strong upturn, from 14 ,000 tonnes in scenario S4 to 34 ,000 tonnes in S6. It should be noted however that those estimates are slightly biased due to our hypothesis that the uranium obtained from reprocessing (URT) is not recycled. Currently, two 900 MWe reactors recycle enriched URT, and EDF is considering limiting recycling to a single reactor. We can estimate that 5,000 to 8,000 tonnes of URT could be suitable for recycling, thus reducing storage capacity needs. Note however that that quantity represents only 2 % of the total needs for natural uranium, hence only a mild influence on the accuracy of the balance of materials. Recycling URT however requires specific enrichment plants, different from those of Eurodif : the URT enrichment operation can therefore only be carried out in countries with an enrichment capacity using the ultra-centrifugation technique (Russia, Germany, Netherlands, England, Japan) and which accept reprocessed uranium.

Interim storage capacity needs

Up to date production from PWRs has resulted in the unloading of almost 17,000 tonnes of spent UOX plus an additional 214 tonnes of spent MOX. Of those 17,000 tonnes of unloaded UOX, 41.5 % (i.e. approximately 7,000 tonnes) were reprocessed, the rest were placed in interim storage. Reprocessing of those 7,000 tonnes resulted in the recovery of approximately 49 tonnes of plutonium. EDF’s stock of separated plutonium varies from 12 to 14 tonnes, which is consistent with a 2-year delay between the separation of the plutonium and its utilisation to manufacture MOX. There remains a stock of almost 120,000 tonnes of plutonium contained in stored spent fuel (UOX and MOX) [1].

As for the depleted uranium, almost 124 ktonnes are currently stored, some in Pierrelatte (capacity exceeding 200 kt) and some in Bessines (200 kt capacity).

Currently, *the spent fuel storage capacities* are located in the reactors themselves and in the reprocessing plants (the La Hague storage pool has a capacity of 14,000 t and plans are under way to increase that capacity to 18,000 tonnes).

(1) In addition to the stock of non-separated spent plutonium, the stocks of non-spent plutonium held in France amounted on 31/12/98 to 75.9 tonnes, including 35.6 tonnes of foreign plutonium (declaration made to the IAEA by the DGEMP). Those quantities include not only the stocks of separated plutonium stored in La Hague or the recoverable scraps at the MOX manufacturing plant, but also the quantities accumulated for instance in the MOX rejects or in the non-spent core of SuperPhoenix.

If reprocessing stops in 2010 and supposing that it is possible to keep the La Hague storage pools independently of the rest of the facility, the new installations to be built would reach a maximum capacity of 30,000 tonnes in S4 (20,000 in S5 and 10,000 in S6). If it were necessary to shut down the pools in La Hague, an approximate additional 15,000 tonnes storage capacity would have to be built.

Construction of the new storage capacities would not start until between 2010 and 2020, except in S1 and S4 if the La Hague capacities could not be kept ; in this case, a new 10,000 tonnes capacity would have to be built during the decade 2000-2010. These results illustrate the advantages to be obtained from maintaing the La Hague storage capacities in operation.

Concerning *other recyclable materials*, this heading mainly covers *depleted uranium and uranium obtained from reprocessing* : currently, both stocks are stored on the Pierrelatte site (or in Bessines, in the case of depleted uranium). Particular attention must be paid to the depleted uranium resulting from uranium enrichment operations, the stock of which would in 2050 amount to 370 kt, plus or minus 30 kt depending on the scenarios. This volume can be likened to an unconventional fissile energy stock for, in the very long term, that stock could be used in rapid neutron reactors, (for instance 1 GWe RNR uses a net capacity of 1 tonne of depleted uranium each year). However, it is not certain the depleted uranium would be used in this way in which case it might even be considered as a waste product. Until its exact status is decided, it must be stored in suitable conditions to protect health and the environment, which is why a dedicated storage installation for depleted uranium was built in Bessines.

Reprocessing capacity needs [1]

The La Hague site comprises two reprocessing facilities with a nominal unit capacity of 800 tonnes per year.

How well does that capacity meet the needs? To find out what those needs are, we remind the reader that the reprocessed volume depends directly on the possibility of recycling plutonium in the form of MOX and that the stock of separated plutonium will be fully used up before recycling comes to an end. Currently, EDF has a reprocessing contract under way with Cogema for 8,000 tonnes. That contract runs through to some time in 2001 and should be renewed to meet the needs of EDF for its existing nuclear power plants. The needs in

(1) We recall that those needs concern the existing fleet and do not take into account the possible needs of the future fleet.

terms of annual reprocessing capacity for the entire fleet of French nuclear power plants in line with our scenarios could be as high as 1,200 tonnes, depending on the number of units loaded with MOX.

That would lead to the following dates for reprocessing to stop : 2010 for S1 and S4, 2022 for S2, 2026 for S3, 2027 for S5 and 2030 for S6.

As La Hague already has two reprocessing facilities, shutdown could presumably be progressive. In the current context of a significant reduction in the fuel reprocessing contracts signed by foreign utilities, that would imply, in scenarios 1 and 4, a probable drop in the reprocessing capacity to 1,000 tonnes each year until definitive shutdown takes place sometime around 2010 ; in scenarios 2 and 5, a probable drop in the reprocessing capacity to 1,000 tonnes each year until production ceases entirely after 2020 ; in scenarios 3 and 6, reprocessing is expected to be maintained at current capacity through to 2015 then reduced to 1,000 tonnes per year until total shutdown after 2025.

Here again, our conclusions are limited to the French nuclear plants and ignore all reprocessing contracts possibly signed with foreign operators and the needs of future nuclear plants : on the first point, the only contracts signed already for the period after 2000 concern Germany (for 1,127 tonnes), the Netherlands (for 165 tonnes) and Australia (for 3 tonnes).

The end of the cycle

This heading covers principally ***spent UOX and MOX fuels***, ***category B waste*** and ***category C waste.*** As regards the very low-level waste produced during reactor and fuel cycle facilities dismantling operations, and category A waste produced by the operation and dismantling of nuclear installations, measures have already been taken : a specific dump for very low level waste will be commissioned around 2002 and the storage centre in the department of Aube has been receiving category A waste since 1992 and has sufficient capacity to meet all the needs of the existing nuclear fleet.

To conclude, this brief examination of the materials balance shows that the major differences between scenarios occur at the back end of the cycle : s*olutions that do not include reprocessing* basically lead to the problem of the interim storage (50 years) and definitive disposal of spent UOX, the cost of which remains uncertain ; *solutions that include reprocessing* result in smaller fuel storage needs yet the management of a much wider array of waste types : spent UOX possibly, hotter-than-necessary spent MOX requiring 2 or 3 times longer storage (i.e. 150 years) before it is ready for definitive disposal. The solutions enable reducing fuel needs, the volume of category B and C waste already conditioned for long-term storage and possibly the volume of plutonium obtained through reprocessing.

Clearly there are many uncertainties weighing on the back end of the cycle both in terms of feasibility and costs, and especially since they concern the very distant future.

3.4. Economic balances associated with the scenarios

The economic results anticipated about the existing nuclear fleet depend very directly on the considerations developed in the presentation of the materials balance.

The *main parameter* is obviously the utilisation of the nuclear plants to more or less full capacity, as illustrated by the *capacity factor* [1] (Kp) and *lifetime*. Utilisation of the power plants will depend above all on the following :

- changing demands for electricity and the distribution of that demand over the year (load curve) ;
- the ability of the operator to maintain ageing facilities in an optimum state of availability ;
- and lastly, more marginally, on the evolution of the cost of natural uranium, which represents approximately 6.5 % of the expenditure on the existing nuclear fleet after the year 2000.

The second most important parameter concerns the back end of the cycle. The selected scenarios present contrasting solutions and highlight a diversity of waste balances. From the economic standpoint, because of the diversity of options, there is a risk that this item will reflect contrasted results inasmuch as there remains great uncertainty as to the technical solutions and calendars. For instance, although we have a fairly accurate idea of the costs of storing certain types of waste, as we have a minimum of experience in the matter. We still have difficulty costing the storage time of spent UOX and MOX and to find the more

(1) The following evolutions could result in a utilisation rate of the fleet that is less favourable than the one we chose in our initial hypothesis (gradual increase in the Kp from 69 % to 85 % at the rate of half a point per annum).

economically desirable solution until the characteristics of the definitive disposal site are known.

It is the same for *dismantling* where calendar and costs are still assessed very differently.

In the economic analysis we present here, a distinction must therefore be made between :

- those aspects of which we can be reasonably certain, i.e. the front end of the fuel cycle, nuclear operations and waste storage ;
- those aspects on which we don't know many things, such as the evolution of nuclear plant availability and the medium and long-term national electricity demand. Those uncertainties affect the evolution of the real capacity factor (Kp) of the nuclear plants and therefore the economics of the entire system. We can grasp the measure of their influence by varying the annual increase in Kp by 0.25 %, 0.5 % or 0.75 % without exceeding the 85 % ceiling ;
- those aspects on which we understand poorly until today, the results of research programmes being not yet available and which mostly would take place after the year 2050, such as conditions for the definitive disposal of long-life, category C and other wastes, and possibly, depending on the options taken up, spent UOX and spent MOX, whose technical solutions and action calendars are still far from settled. The future of category B waste however, is likely to pose fewer problems.

Caution should therefore be exercised when interpreting the table below which summarises the overall results of our analysis for the six scenarios outlined earlier.

Economic balance

In billions of FF (constant Francs 1999)	S1	S2	S3	S4	S5	S6
Capital investment	470	470	470	470	470	470
Immediate dismantling (Dmt I)	128	128	128	128	128	128
Deferred dismantling (Dmt D)	112	112	112	112	112	112
R & D	100	100	100	100	100	100
S/t capital investment (Dmt I)	**698**	**698**	**698**	**698**	**698**	**698**
S/t capital investment (Dmt D)	**682**	**682**	**682**	**682**	**682**	**682**
Operation	1 035	1 035	1 035	1 109	1 109	1 109
Post-operation	66	66	66	66	66	66
Upkeep & maintenance	109	109	109	122	122	122
S/t operation	**1 210**	**1 210**	**1 210**	**1 297**	**1 297**	**1 297**
Front end 1977-1998	271	271	271	271	271	271
Front end 1999-2049	284	275	266	331	318	307
S/t front end	**555**	**546**	**537**	**602**	**589**	**578**
Back end 1977-1998	93	93	93	93	93	93
Back end 1999-2049	97	120	147	102	139	170
S/t back end	**190**	**213**	**240**	**195**	**232**	**263**
End of cycle B + C	18	24	31	18	27	35
End of spent fuel cycle	85	77	68	94	82	72
S/t end of cycle	**103**	**101**	**99**	**112**	**110**	**107**
S/t back and + end of cycle	**293**	**314**	**339**	**307**	**342**	**370**
S/t cycle	**848**	**860**	**876**	**909**	**931**	**948**
Total (immediate Dmt)	**2,756**	**2,768**	**2,784**	**2,904**	**2,926**	**2 ;943**
Total (deferred Dmt)	**2,740**	**2,752**	**2,768**	**2,888**	**2,910**	**2,927**
Electricity generation (TWh)	18 111	18 111	18 111	20 238	20,238	20,238
Mean cost [1] of the kWh in centimes	15.13	15.20	15.28	14.27	14.38	14.46

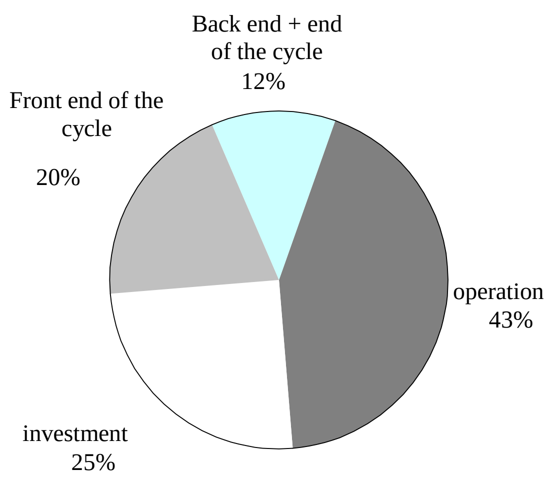
Source : Working group on the « Existing Fleet of Nuclear Plants »

(1) That average cost differs greatly from the « reference costs » calculated by the DIGEC (20 to 21 c/kWh): here, we have an average expenditure calculated over the entire production period of the existing fleet whereas the DIGEC "cost" is a discounted economic cost calculated, for a given item of equipment, based on its base-load characteristics and for different durations of use each year. For a given duration of use, the economic reference cost of a kWh for a given facility is obtained by discounting at the date of commissioning, all expenditure on capital costs, operating costs and fuel costs over the lifetime of that facility (including expenditure for the front-end and back-end of the nuclear cycle) and comparing the cost thus obtained with the discounted sum of the energy produced.

Using the hypotheses selected in the previous paragraph, the table reconstitutes the **non-discounted** cumulative expenditure on the existing fleet of nuclear plants, for the following main items :

- the capital investment (construction, dismantling, R & D) ;
- the operating overheads (operation proper excluding cost of fuel, cost of upkeep/maintenance, expenditures on post-operation) ;
- the front end of the cycle (natural uranium, conversion, enrichment, manufacture of UOX) ;
- the back end of the cycle (reprocessing, manufacture of MOX, storage of URT and depleted uranium, storage of non-reprocessed fuels, storage of waste while awaiting disposal, dismantling of the UP2-800 factory) ;
- the end of the cycle (storage of category B & C waste, storage of non-reprocessed spent UOX and MOX fuels).

The first observation concerns the share of cumulative expenditure per item in all of the scenarios, as represented by the graph.



In decreasing order, we find :

- the operating overheads for the nuclear power plants over the period 1977-2050 which represent 43 to 44 % of the cumulative expenditure ;
- the fuel cycle-related expenditure, representing approximately 32 % of the cumulative expenditure, including two-thirds (20 %) for front-end and only one-third for the back end of the cycle (12 %) ;
- the capital investment-related expenditure of around 25 % of the cumulative expenditure, 80 % of which has already been paid, the remaining 20 % representing future expenditure on the dismantling of nuclear reactors and expenditure on R & D for the period 2000-2030.

- **Operating overheads**

Those expenses depend on the effective production of the nuclear power plants, with an elasticity [1] of around 0.6 : for an 11 % higher overall production in scenarios S4, S5 and S6 (lifetime of 45 years) than in scenarios S1, S2, S3 (41 years), the operating expenditure increases by 7.1 %. Similarly, the calculation performed for a different evolution of the capacity factor Kp over time [2] shows that the increase in electricity production obtained in the high hypothesis (+ 5.8 %) leads to an increase in operating expenditure of 3.4 %. Alongside that variation in production, the uncertainty as to the anticipated expenditure for upkeep (300 MF/GWe after 10 years, 600 MF/GWe after 20 years, 600 MF/GWe after 30 years, 500 MF/GWe after 40 years, i.e. 10 % of the total operating expenditure) has only a relatively minor impact on the cumulative costs.

(1) The elasticity is defined as the additional expenses needed for an additional production of one unit.

(2) Low-capacity hypothesis: Kp increases from 0.25 % per annum up to a ceiling of 80 % in 2044, i.e. a mean Kp of 75% over the period 2000-2050. Reference (median) hypothesis): Kp increases from 0.5 % per annum up to a ceiling of 85.5 % in 2033, i.e. a mean Kp of 78 % over the period 2000-2050. High-capacity hypothesis: Kp increases from 0.75% per annum starting in 2000 up to a ceiling of 85 % in 2022, i.e. a mean Kp of 82 % over the period 2000-2050.

- **Capital investment**

Those expenses are the same in all scenarios, and almost 80 % of the expenditure has already been made for the research and construction of the reactors (470 billion French Francs). The remainder, namely the outstanding expenditure, may still change depending on the calendar and techniques chosen for dismantling the power plants. EDF indeed proposes a 60-year, three-stage calendar : definitive shutdown, resulting in costs of approximately 50 % of the total expenditure, spread over about ten years ; monitoring for the next 40 years (10 % of expenditure) and final dismantling over the last 10 years (40 % of expenditure). The total expenditure [1] is evaluated by EDF at 1,700 F/kWe.

We also explored a faster dismantling strategy, which avoids the very long wait proposed by EDF but implies more acute technical problems inasmuch as work has to be performed in a much more radioactive environment in the first 15 years after definitive shutdown of the nuclear power plants. With this hypothesis, the cost could reach as much as approximately 2,000 F/KWe.

All of those costs nevertheless remain uncertain and are likely to move gradually as experienced is acquired, and as the regulatory requirements forming the framework for the dismantling process are gradually put in place. Nevertheless, we see, with the chosen hypotheses, that future expenditure represents only around 4 % of the cumulative expenditure. Even if those costs were to increase on a significant manner (if doubled, for instance), the influence of that variation in the cost of the programme would still be fairly modest (approximately 8 % of the cumulative total expenses for the programme).

- **Front end of the cycle**

Expenditures on the front-end of the cycle, amounting to 44 to 50 % of the expenses paid over the years 1977-2000, depending on the scenarios, include the costs involved in the purchase of natural uranium, fuel conversion, enrichment and fuel manufacture.

For a given lifetime, for instance 45 years, “front-end-of-the cycle”expenditures are 4 % higher in the scenario where reprocessing stops, compared to those expenditures in the other scenarios. In this scenario, 2,300 tonnes of UOX fuel must be manufactured from natural uranium since MOX manufacture stops

(1) i.e. approximately 15 % of the investment cost according to the methodology chosen by the secretariat of State for Industry within the framework of the « electricity production reference cost » exercise.

after 2010. The influence of the various strategies on cumulative expenditure nevertheless remains very modest (less than 1 % of the total cumulative expenditures).

The expenditures were calculated by assuming a modest increase in the price of uranium over the period, which increases from 300 FF per kilo in 2000 to 400 FF in 2050. Should the price of uranium rise a lot faster, the influence of such an increase would nevertheless remain modest inasmuch as the cost of the natural uranium represents only approximately one-third of the total cost of the UOX fuel. In the opposite case, where the price of uranium remains at its present level (around 200 FF per kilo) over the entire period, the savings achieved in scenarios S6 compared to scenario S4 would be less than 0.5 billion of french francs.

Analysis of the repercussions of a differentiated evolution of Kp over the period 2000-2050 on fuel needs shows that a 5.8 % increase in electricity production as a result of an increase in average Kp from 75 to 82 % results in a 3.4 % increase in the cumulative expenditures on fuel. In all, when we add up all operating overheads and expenditure on fuel, the 5.8 % cumulative increase in electricity production allocated to the 75 to 82 % increase in average Kp results in an additional expenditures of 3.4 % (elasticity of 0.6).

- **Back end of the cycle**

This part of the technology is where the scenarios differ the most. Indeed, for a given lifetime of 41 years, for instance, we see that scenario S3 which incurs most reprocessing generates an additional cost of 50 billion FF (26 %) over scenario S1 where reprocessing stops in 2010. That considerable difference is concentrated solely over the period 2010-2050 [1].

This item comprises the activities of spent UOX reprocessing, recycling of plutonium separated from the MOX, storing the non-reprocessed spent UOX and spent MOX, and long-term storage of category B and C waste prior to

(1) Scenario S7 presented in the annex, which assumes no reprocessing from the outset, highlights the consequences of the two strategies on the back end of the cycle - if one compares their cumulative results from the outset of the fleet: a difference of a factor of more than 3 can be seen between the strategy without reprocessing (S7) where the cost amounts to 86 billions FF and the « 28 MOX units » strategy (S6) where the cost amounts to 263 billions FF.

definitive disposal. The expenditures on storage were calculated [1] in two different situations, one which includind the option of storage in the La Hague facility even if reprocessing was discontinued, the other excluding that option. The two alternatives present a differential cumulative expenditure of 14 billions french francs (184 billions FF without the La Hague storage pools and 170 billions FF with the pools for scenario S6).

- **Definitive disposal**

This item is the one on which we find the biggest economic uncertainties : storage costs for category B and C waste or spent fuels will depend on the nature of the storage site finally chosen and potential mandatory requirements for the more or less total reversibility of that storage. The international estimates used in the scenarios lie within a broad range that varies (for category C waste) from 0.6 MF per m^3 in Germany to 3.5 MF per m^3 in the United Kingdom, according to a study conducted by the Agency for Nuclear Energy (Agence pour l'Energie Nucleaire, AEN) several years ago.

Figures communicated by the national radwaste management agency, ANDRA, are situated towards the top of the range (0.4 MF per m^3 for category B waste and 4.2 MF/m^3 for category C waste). If we apply those figures to the various scenarios we can put forward an order of magnitude to the cumulative expenditure for the storage of those wastes that varies from 18 billions french francs in the "reprocess stops" scenarios and 35 billions french francs in scenario S6.

The uncertainties appear to be similar at least, for the storage costs of spent UOX and spent MOX. Current estimates on storage vary greatly today (in a ratio of 1 to 3, according to a study made by the AEN on spent UOX fuel).

It is obvious that the unit costs of storing both spent UOX and spent MOX will have considerable repercussions on the cumulative storage cost differentials between the various scenarios. Indeed, we recall that, for a lifetime of 45 years, scenario S4 requires storing 41,000 tonnes of spent UOX, compared to only

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(1) This calculation was done by the working group on « The existing fleet of nuclear plants » set up under the mission. The group studied the consequences of « whether or not it was possible to retain the La Hague storage capacities for the UOX and category C waste even in the event of shutdown of the reprocessing plants ». For MOX, given the lengths of storage time, the group hypothesised that was not possible to keep the storage pools of La Hague.

17,000 in scenario S6. However, that same scenario assumes the storage of 4,800 tonnes of spent MOX compared to 2,000 tonnes in S4.

Based on data supplied by ANDRA on the unit cost of UOX storage (after 50 years' interim storage) and MOX (after 150 years' interim storage), we obtain storage costs for spent fuel varying from 68 billions FF for scenario S3 to 85 billions FF for scenario S1 (service life of 41 years) and from 72 to 94 billions FF for the S6 and S4 (service life of 45 years), highlighting a considerably higher cost for storage in the "reprocessing stops" scenarios [1] (34 billions FF in scenarios with a mean 41 years lifetime for the nuclear plants and 22 billions FF for 45 years).

Altogether, the overall expenditure on storage shows an additional cost of 4 billions FF for the solution where reprocessing stops in 2010 according to the hypothesis of a 41-year lifetime and 5 billions FF for the 45-year lifetime.

Those conclusions must however be viewed cautiously since there are uncertainties on the unit costs of storage of the different spent fuels and on the action calendar. In particular the length of interim storage for UOX and MOX respectively, may considerably distort the results obtained.

- **Overall result**

In all, when looking at the overall economic results for the existing reactor fleet (considered separatly) for a given average lifetime of the plants, we see that the cumulative expenditure in the different scenarios fluctuate slightly, as results at the front end of the cycle offset those at the back end. In the end, they result in only slight differences (of around 1 %) between the non-discounted average cost of the kilowatt-hour, which ranges from 15.13 to 15.28 centimes per kilowatt-hour in scenarios S1, S2, S3 and 14.27 to 14.46 centimes per kilowatt-hour in scenarios S4, S5 and S6.

Moreover, that apparent similarity is basically due to the fact that the majority of expenditures relating to the reprocessing-recycle strategy, and particularly the heavy capital cost invested in La Hague and Melox facilities, has already been committed, and that reprocessing will not be phased out until 2010, by which time the existing reactor fleet will already have generated approximately half of the total electricity production for its entire service life. As regards total capital

(1) In case of reprocessing, a diversification occurs of the waste types to be stored. Although this can have advantages, it can also lead to extra costs, for instance, if problems are encountered with one of the waste categories.

investment chosen for the existing fleet, three-quarters of the projected capital investment between now and 2050 (525 billions FF) has already been spent and of the total overall costs forecast for that same period (between 2 740 and 2,927 billions FF depending on the scenarios) almost half (1,231 billions FF) has already been spent. Therefore, out of the remaining expenditure to be made between now and 2050 for the existing fleet (from 1,509 to 1,696 billions FF depending on the scenarios), there remains differential latitude of 187 billions FF between the various scenarios, i.e. 6 to 7 % of the total expenditure relating to the existing fleet between 1977 and 2050, or 11 to 12 % of the expenses still to be covered.

In terms of cumulative total cost, the saving achieved in the "reprocessing stops in 2010 » scenarios, compared to the « 28 MOX units » scenarios, therefore amounts to 28 to 39 billions FF, depending on the chosen lifetime hypothesis.

With or without reprocessing, for instance, scenarios S4 and S6 basically differ as regards their balances in terms of the non-separated plutonium + americium for storage. Compared to scenario S4, scenario S6 avoids the definitive disposal of 88 tonnes of non-separated Pu + Am for an additional cost of 39 billions FF [1]. In view of the expenditure already committed, that represents an implicit marginal cost of 445 millions FF per tonne of plutonium + americium avoided.

To ***conclude***, we can estimate that pursuing the French reprocessing-recycle strategy, if fully implemented on the existing reactor fleet (28 "MOX" units) and in optimal conditions of operating capacity at La Hague, over the service life of the current reactor fleet considered in isolation, and compared to stopping reprocessing in 2010, would enable :

- an approximate 5 % saving in natural uranium ;
- a reduction of approximately 12 to 15 % of the quantities of plutonium + americium to be stored, depending on the service life of the reactors.

(1) To obtain an « implicit average cost of the tonne of plutonium + americium avoided », we compared (see annex) the economic balances of scenarios S5 and S6 with that of a scenario S7 (fictitious scenario in which no investment was made for the La Hague and Melox sites). The resulting cost is from 1.1 billion FF to 1.3 billion FF per tonne of plutonium avoided.

Those reductions would be achievable with an overall extra cost of 1 % (28 to 39 billions FF) and by prolonging the interim storage period for some of the waste products (spent MOX in particular having to be placed in interim storage until 2150-2200) prior to definitive disposal.

Chapter 2

The international situation

Before reviewing possible electricity supply scenarios for France between now and 2050, we can usefully consider the development of the nuclear power industry around the world. The situation of power production facilities across the world has been influenced by the differential response to a variety of factors such as the trend in the world fossil or fissile fuel prices, the dynamism of government-sponsored R & D programmes, the risks of accident, the safety considerations, the emergence of environmental problems on a global scale, the decisions taken up for the back end of the cycle, the comparative economics of different systems, etc. Changing perceptions in different countries like the decisions made in those countries on reactor lifetimes or whether to renew facilities, like the responses to environmental problems and the inevitable repercussions on the economics of the different systems, like the development of political and economic lobbies, and other factors, all impact the evolution of the nuclear industry on an international level.

How will all these changes impact the situation in France ? Some are easier to define than others : can we, for instance, consider France maintaining a reprocessing strategy if other countries turn their backs on it ? Can we continue to pursue the nuclear option if other countries abandon it ? Conversely, if there is a dynamic market for nuclear energy in some areas of the world, or if programmes are actively being implemented in the industrialised countries to reduce the greenhouse effect, should we not opt for the economics of nuclear energy and therefore encourage a strong development of that industry in the Western world ?

The nuclear industry is clearly an industry of international scope, the future of which will be shaped as much by developing world dynamics as by the policies of individual nations.

The situation of nuclear energy across the world is extremely contrasted : many countries or regions in the world have no nuclear reactors, whereas those that do have recourse to that particular system of energy production form a very mixed group. Those contrasts from one country to another relate to differential assessments of the risks incurred with nuclear energy, as the short history of nuclear development has been marked by different perceptions on the benefits and risks involved.

Although the development of the civil nuclear industry has been guided everywhere by the same concerns, the results indeed vary depending on the options taken up and differences in timing from one region of the globe to another, or even within a region, from one country to another. Ranking those concerns according to the order in which they appeared on the international scene, we cite :

The military use of the atom, or proliferation : for many States, the programmes promoting peaceful uses of nuclear energy to produce energy are often rooted in a military programme. This is true in all of the five states – the United States, Russia, Great Britain, China, France – fitted out with an atomic weapon. The same is true also for the states of the former USSR and those who once had the ambition of developing nuclear energy for military purposes, whether that ambition saw tangible results as in India, Pakistan, South Africa or not, as in Brazil, Argentina and Iraq. Last of all, other states, for instance Germany, Japan and South Korea, developed directly their civil nuclear industry. Thereafter, the will of the leading nuclear nations to put an end to proliferation led to the adoption of international instruments (non-proliferation treaties) to combat proliferation and the enactment of regulations on the transfer of fissile materials and technologies (Zangger, NSG), making it increasingly difficult for states, and particularly those (Iran, Algeria) suspected of engaging in proliferation to develop nuclear power generation programmes.

The economic competitiveness of nuclear energy : the competitiveness of nuclear energy and the fact that the cost of each kilowatt-hour of electricity produced using nuclear energy is less vulnerable to outside influences played a determinant role in the development of massive nuclear electricity programmes in different countries, particularly in the wake of the first oil crises. Increasingly stringent safety requirements however, and lower petrol prices slowed down the infrastructure projects and reduced the market for nuclear plants. In some countries the cost of electricity production actually increased with the use of nuclear energy, although that increase was often offset by improvements introduced to optimise power plant operation (more reliable power plants on the grid, depreciation of the investment, longer service life) and reactor performance (particularly through the fuel).

Economy of energy resources and independence of the power supply : the oil crises spotlighted the direct economic risk of depending too heavily on one country or region for petroleum products. Such concerns fostered the development of nuclear energy, particularly in countries like France or Japan where fossil resources were scarce, at the time when fears of a shortage of fissile resources similar at the one of fossil resources was developing. This in turn spurred the development of more efficient nuclear technologies based on the use of enriched rather than natural uranium as a fuel. Later still, the search for even greater efficiency looked to the plutonium formed in the spent fuel, which implied reprocessing the fuel. However, systems based on the plutonium cycle, supergenerators for example, have not met with the anticipated success in terms of industrial development.

Risk of accident : after the Three Mile Island accident in 1979 in the United States, and particularly after Chernobyl in 1986, which gave clear indication of the regional or global scale of a major nuclear disaster, the international community feared the possibility of a new, more serious accident. That event triggered a growing movement away from nuclear energy in every country, to the point that led most of them either to slow down their nuclear programmes, impose a moratorium, shut down facilities or even abandon their nuclear programm.

The future of nuclear waste : management of the waste produced by the nuclear industry was not, in the early days, the prime concern of the nuclear operators. In the case of low-level activity waste, management for a long time stayed on the principle of diluting those products in the environment (for instance, by immersion [1]). However, dealing with the waste without affecting the environment has gradually become a prime matter of concern for operators [2],

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(1) France immersed low level activity radwaste only on two occasions, in 1967 and in 1969 before opting for surface storage.

(2) In France, diverse solutions for the management of high level long-life waste are being studied under the framework of the law passed on December 30th 1991, which stipulates a research program along three lines :

- *separation-transmutation (study of solutions to substantially reduce the quantity and toxicity of the radwaste) ;*
- *storage in a deep geological repository (a solution likely to become definitive without human intervention as the geological scope allows confinement to be assured on the scale of the characteristic lifetimes of long-life radionuclides, while maintaining the option of reversibility for a while at least) ;*

resulting on the contrary in management based on the practice of concentrating and confining the waste in order to ensure its disposal.

Management of the different categories of waste produced by the nuclear industry is currently based on a principle of confining the radioactive waste by conditioning it into packages. Packages of high level long-life waste are stored in surface or underground facilities generally while awaiting storage in the deep geological formations. In 1999 the United States brought into operation their deep geological repository for medium level long-life waste in New Mexico. Low level activity, short-life waste is surface-stored (the practice of immersing certain amounts of this type of waste was abandoned forever in the 60's after the London conference, and within the framework of the OSPAR agreement).

Combating the greenhouse effect : the latest argument of significance in the debate on the benefits of nuclear energy stems from the increasing concern with the risk of global warming. The nuclear industry currently offers an alternative to fossil energy sources among policies aiming to reduce the greenhouse gas emissions. However, the plans introduced to combat the greenhouse effect have not, as yet, led to a renewal of interest in nuclear energy.

The way countries react to those concerns has led to a huge diversity in the situations of the different countries and the extent to which each meets its national electricity demand with nuclear energy.

1. The dynamics of nuclear energy across the world

Nuclear electricity generating systems can be placed in six main groups, each representing a different technology whose dynamism may have varied at times, depending on the economics of each technology and the extent to which nuclear energy is used in those countries that have opted for one of those technologies.

- *conditioning and long-term storage (method of management monitored by the utility, in long-term surface or shallow storage installations suitable to protect the package after prior conditioning in a form that guarantees durable confinement and the possibility of recovering the packages in safe conditions according to established technical procedures).*

The law sets a calendar, stipulating a date in 2006 when a general report evaluating the research will be submitted to Parliament with a view to decide the management options for each of the three avenues of research.

- AGR (Advanced Gas Reactors) and MGUNGG (Magnox Uranium Natural Gas Graphite Reactors). The United Kingdom currently has 34 of these units in operation, which use gas for the coolant, graphite for the moderator and enriched uranium (UO2) for the fuel.

- PHWR (Pressurised Heavy Water Reactors) : 39 reactors are in operation, including 21 in Canada, 10 in India and 4 in South Korea ; 11 reactors are currently being built and 6 are on order, including 4 in India and 2 in China ; they use heavy water for both the coolant and the moderator and natural or enriched uranium for the fuel.

- Ordinary water reactors. The three types of reactors (PWR, BWR and VVER) belonging to this category use pressurised ordinary water (for PWR and VVER) or boiling water (for BWR) as the coolant ; they use ordinary water as the moderator and enriched uranium (UO2) or MOX (a mix of uranium and plutonium) in association with enriched uranium as the fuel.

  PWR (Pressurised Water Reactor) or REP in French (Réacteur à Eau Pressurisée) : 207 are installed, including 69 in the United States, 58 in France, 23 in Japan, 14 in Germany and 12 in South Korea ; 12 are under construction, including 4 in South Korea and 4 in China.

  BWR (Boiling Water Reactor) or REB in French (Réacteur à Eau Bouillante) : 91 are installed, including 35 in the United States, 28 in Japan and 6 in Germany ; 9 are currently being built or are ordered, including 7 in Japan and 2 in Taiwan.

  VVER reactors (Vodiano Vodianoi Energuietititcheski Reaktor) : 49 are installed, including 13 in Russia and 13 in the Ukraine, 6 in Slovakia ; 22 are currently under construction or ordered, including 11 in Russia and 4 in the Ukraine.

- Rapid Neutron Reactors (réacteurs à neutrons rapides), or supergenerators, can use sodium as the coolant and a mix of uranium UO_2 and plutonium PuO_2 as the fuel. The total net installed capacity amounts to 1 066 MWe (4 reactors, divided among France, India, Japan and Russia) and the net capacity under construction or ordered amounts to 3 020 MWe (of which 3 000 are found in Russia).

- RBMK (Reaktor Bolchoi Mochtchnosti Kanalni) water-graphite reactors and GLWR (Graphite Light Water Reactor) use ordinary boiling or pressurised water as the coolant, graphite as the moderator and enriched UO_2 or natural uranium as the fuel. The total installed capacity is 13 904

MWe divided between 18 reactors, of which 10 210 (11 RBMK) are in Russia, and one 925 MWe RBMK reactor currently under construction in Russia

- ATR (Advanced Thermal Reactors) use ordinary boiling water as the coolant, heavy water as the moderator and enriched UO_2 – PuO_2 as the fuel. Only one ATR reactor of 150 MWe is in operation, in Japan.

Historically, a large number of prototypes have been built for the different systems. Currently, one system dominates the nuclear market, and that is the light water reactor, in its three versions : PWR (REP, in French), BWR (REB, in French) and VVER. One other system is being developed as a niche strategy, the PHWR, with smaller capacity reactors (700 MWe).

World situation for nuclear power units 31/12/1999

(Breakdown per system or group of systems), power in net MWe (number of units)

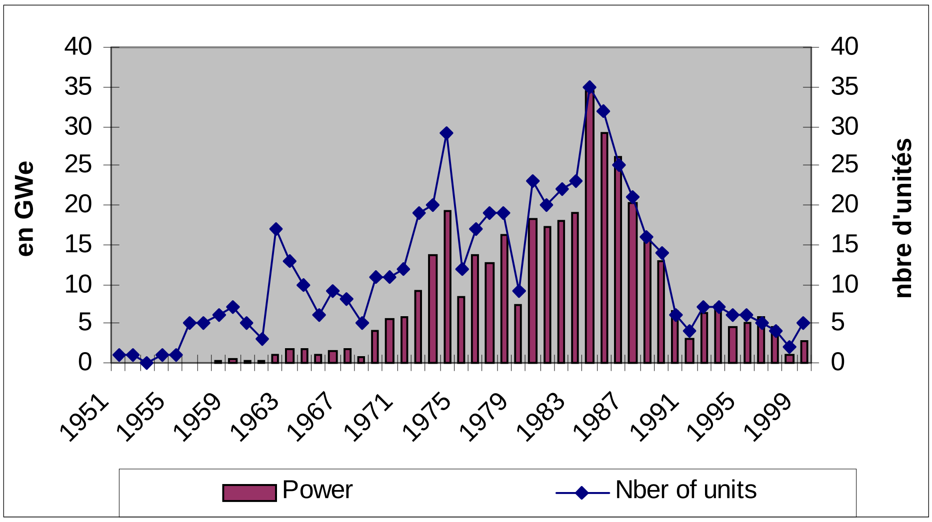
Grouped systems	Installed		Under construction		Ordered		Removed from the grid		Cancelled	
AGR, MGUNGG, UNGG	11 738	(34)	-	-	-	-	4 228	(19)	250	(2)
PHWR	21 231	(39)	5 816	(11)	1 708	(6)	1 135	(5)	1 275	(2)
PWR	198 618	(207)	10 219	(12)			8 048	(21)	127 633	(118)
BWR	79 009	(91)	7 231	(6)	3 559	(3)	4 886	(28)	53 056	(49)
FAST-FBR	1 066	(4)	3 020	(5)	-	-	1 726	(10)	2 145	(3)
VVER	30 923	(49)	15 860	(18)	2 560	(4)	3 463	(10)	46 525	(57)
RBMK, GLWR	13 904	(18)	925	(1)	-	-	4 457	(13)	6 460	(6)
ATR	150	(1)	-	-	-	-	-	-	-	-
MISC.	-	-	-	-	-	-	1 479	(17)	11 853	(16)

Source : ELECNUC, CEA

The industrial commissioning dates of the first nuclear plants differ depending on the country and on the systems : 20/12/1951 (Fast breader reactor) in the United States ; 27/6/1954 (RBMK) in Russia ; 27/8/1956 (MGUNGG) in the United Kingdom ; 38/9/1956 (UNGG) in France ; 17/6/1961 (BWR) in Germany ; 04/6/1962 (BHWR) in Canada ; 10/10/1962 (PWR) in Belgium ; 12/5/1963 (BWR) in Italy ; 26/10/1963 (BWR) in Japan ; 20/3/1964 (PHWR) in Sweden ; in 1968 (PWR) in Spain and (BWR) in the Netherlands. For the other nuclear power producing countries, the first industrial commissioning dates spread over the eighties and nineties, the most recent "first industrial commissioning" having taken place in Romania (PHWR).

564 nuclear power reactors went critical in the world between 1951 and 1999, representing a cumulative total power of 384 GWe. The annual number of new connections to the grid reached a peak in the mid-eighties.

Annual evolution of connections to the grid



Source : based on ELECNUC CEA data

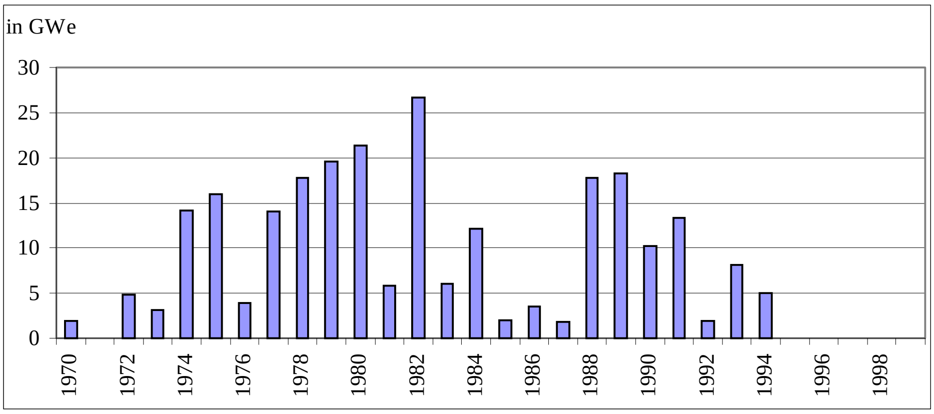
The world fleet of nuclear reactors is divided between 32 countries and today amounts to a net capacity of 356 GWe, of which 80 % is installed in OECD countries (98 GWe in the United States with 104 reactors, 63 GWe in France with 59 reactors and 43 GWe in Japan with 53 reactors). Those reactors were put by place by successive phases :

- the prototypes phase will low capacity reactors at the start of the sixties ;
- the first wave of industrial units starting in the early seventies, particularly in the United States ;
- a first wave of cancelled orders towards the end of the seventies (in the United States especially) as a result of difficulties in getting the projects off the ground either from a financial and regulatory aspect and/or as a

consequence of a shift in public opinion after the Three Mile Island accident which occurred in 1979 ;

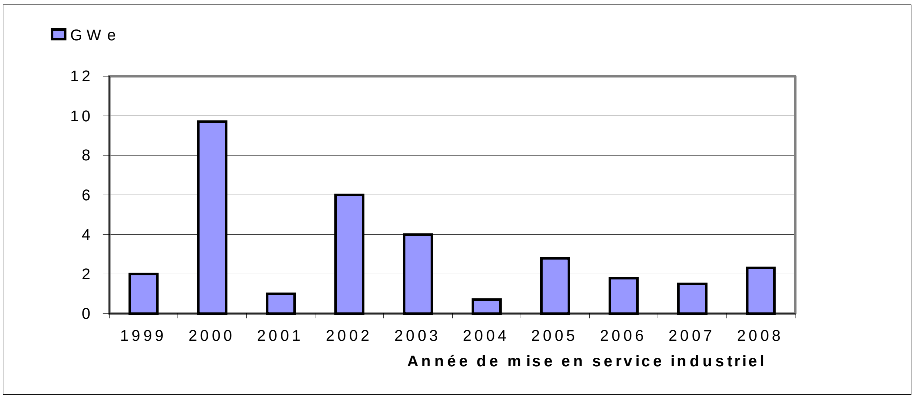
- the second wave of power plant construction in the eighties as a result of decisions made after the two oil crises in 1973 and 1979 ;
- a second wave of cancellations at the end of the eighties following the Chernobyl disaster in 1986 and the changing political scene in Eastern European countries ;
- the current phase of construction concerns mainly China, Russia and India, and although there have been few industrial commissionings as few shutdowns or cancelled orders.

Cancelled orders for nuclear reactors across the world



Source :based on ELECNUC CEA data

Nuclear power plants under construction in the world



Source : ELECNUC 1999

1.1. The existing fleet

Most of the world's nuclear reactors are situated in the OECD countries, however only a few of those countries are currently building any new reactors, like South Korea, Japan or the Czech Republic. In the longer term, some projects may eventually come to fruition in China, India, Turkey and Finland.

World nuclear electricity production capacity, in operation on 31/12/1999

Breakdown per groups of countries, power in net MWe (number of units)

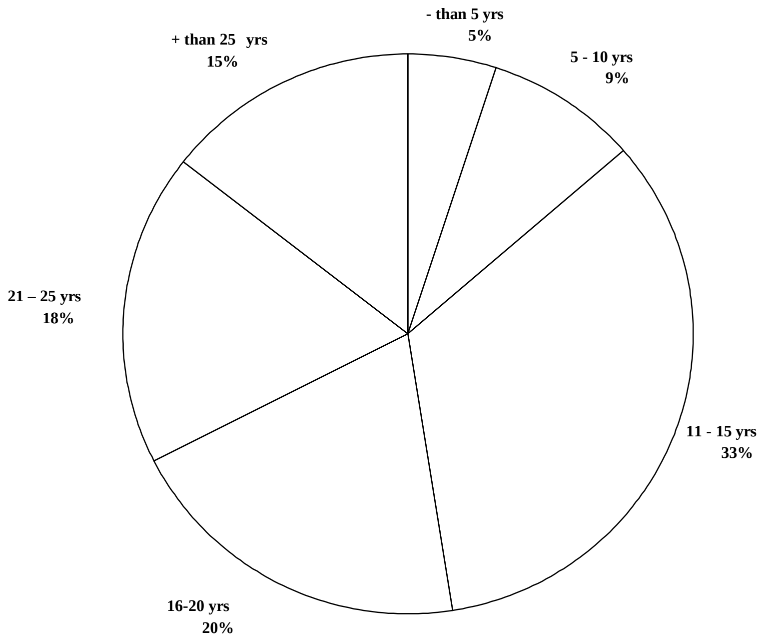
Grouped countries	Installed		Under construction		Ordered		Removed from the grid		Cancelled	
North America (1)	113 043	(125)	-	-	-	-	12 254	(51)	151 175	(139)
EU (2)	124 194	(146)	-	-	-	-	11 716	(48)	32 592	(40)
Europe other than EU (3)	3 709	(6)	-	-	-	-	8	(1)	3 120	(4)
Eastern Europe (4)	45 077	(67)	19 455	(24)	2560	(4)	5 260	(20)	48 301	(54)
Asia (5) *	65 903	(92)	21 695	(27)	5267	(9)	184	(3)	11 946	(13)
Rest of the World (6)	4 713	(7)	1 921	(2)	-	-	-	-	2 063	(3)

Source : ELECNUC 2000

(1) Canada, United States.
(2) Germany, Austria, Belgium, Denmark, Spain, Finland, France, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, United Kingdom, Sweden
(3) Slovenia, Switzerland, Turkey
(4) Armenia, Azerbaijan, Byelorussia, Bulgaria, Georgia, Hungary, Kazakhstan, Lithuania, Poland, Czech Republic, Romania, Russia, Slovakia, Ukraine.
(5) Bangladesh, China, North Korea, South Korea, India, Indonesia, Iran, Japan, Pakistan, Philippines, Taiwan, Thailand, Vietnam.
(6) Africa and Latin America, South Africa, Egypt, Argentina, Brazil, Cuba, Mexico.
** Compared to the figures published in Elecnuc 2000, it appears that the figures for Asia should be amended to reflect a drop in construction capacity (17 098 MWe, 23 reactors) and a rise in the capacity on order (8 161 MWe, 9 reactors).*

The industrial commissioning of the oldest reactors in the world still in operation today date back to the early seventies, and those are particularly numerous in the European Union. Mention should also be made of the old British MGUNGG units commissioned between 1956 and 1962, they too are still operating.

One third of the overall world reactor fleet in operation today is more than 20 years old, whereas almost 55 % of them are between 10 and 20 years old, and over 13 % of them under 10 years.



Reactor shutdown forecasts are considered with great uncertainty, firstly regarding the real lifetime of the individual reactors (from 30 to 60 years) and secondly as regards the policies conducted by the different countries in the face of often fluctuating public opinion. According to the data available today, the CEA forecasts for the period 2000-2020 the shutdown of 237 reactors across the world having reached the end of their lifetime. That represents a capacity of 160 GWe, i.e. 45 % of the reactor fleet currently in operation. The number of shutdowns is expected to peak around 2010 (one-third of the fleet having been commissioned before 1980), although the peak of the curve may be attenuated somewhat if the service life of some of the current reactors is extended.

Let us look first of all at what is happening today in the **United States** which has the largest fleet in the world with 104 reactors amounting to a total capacity of 98 GWe (i.e. almost 30 % of the installed power in the world), including 66 GWe produced by PWR and 32 by BWR. The American reactors are issued with operating permits of limited duration, generally 40 years, fixed by the American safety organisation, the *Nuclear Regulatory Commission* (NRC). Those permits come up for renewal only once, for a further period of 20 years. As a large majority of the infrastructures will reach the end of their 40 year lifetime between 2010 and 2015, many operators are already wanting to know how much longer they will be able to operate their reactors, so as to make the capital investment needed for maintenance and upkeep now and obtain a return on investment over the extended (60-year) service life of the reactor. At the start of the year 2000, the NRC announced that it would be announcing its intentions concerning the 18 permits shortly coming up for renewal, as a number of operators have not indicated their wishes yet. A first batch of renewals were granted in April 2000 for the two Calvert Cliffs reactors industrially commissioned over the period 1975-1977 (renewal applied for in April 1998). One month later, renewals were granted for the three units of the Oconee power plant commissioned industrially over the period 1973-1974.

The situation appears, however, to be somewhat blurred in that country : firstly, no American utility is currently considering re-investing in a new nuclear capacity for power generation since gas or coal-fired power plants are considered more competitive to meet new demand. Secondly, the liberalisation of the electrical industry (well under way in 22 States) is leading to a *split up & merge* process which may eventually result in a small number of players of much greater size (ten or so, compared to approximately 50 at present). Some of those players gamble on the existing nuclear capabilities, not hesitating to purchase [1] nuclear plants immediately when the operator puts them on the market. As the capital investment has generally been fully paid off by then, nuclear energy proves competitive compared to fossil energy.

Although the high number of applications being made to extend the operating permits of nuclear plants may seem encouraging for promoters of nuclear energy, mistrust of nuclear energy remains strong in America, and the cost [2] is high for investors looking to build a new reactor. Neither has the problem of high-level long-life waste yet found a solution. Nevertheless, the preparation of generic safety reports might reduce construction times and make nuclear power a more attractive option.

The situation of electric utilities is highly diversified in **Europe**. Of the fifteen member countries of the European Union, seven rely to varying extent on electricity from nuclear energy – in 1999, the percentage of electricity produced

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(1) As an illustration of that interest, we can indicate that if the sale of reactors commissioned 25 years ago had taken place 2 years ago at a cost of 33 $/kWe, this price has now reached 1 000 $/kWe.
(2) For instance, according to informations obtained from the French Embassy, some industries set the bar at 1 000 $/kWe (installed) for the construction of new reactors in the United States, so as to have a total cost of less than 3 cents/kWh, an objective that appears very difficult to reach.

in nuclear plants amounted to 75 % in France, 58 % in Belgium, 31 % in Germany and Spain, 30 % in Finland, 28 % in the United Kingdom and only 4 % in the Netherlands.

In **Belgium**, the nuclear fleet comprises seven PWR reactors with a total net capacity of 5 713 MWe. The first three (i.e. 30 % of total capacity) underwent the industrial commissioning process in 1975 and the remaining four between 1982 and 1985. Belgium had a reprocessing plant (Eurochemic) which was shutdown during the seventies and currently reaching the end of the dismantling process.

In **Germany**, the first electricity production from nuclear sources dates back to 1964. The nuclear capacity progressed rapidly to reach almost 30 GWe in 1990. Currently, the average age of the reactor fleet is fairly high, approximately 20 years, and in the face of the somewhat hostile public reaction to nuclear energy, Germany committed in January 1999 to abandon nuclear power generation. An agreement [1] was signed on June 14th 2000 between the government and the electric utilities to gradually phase out the entire nuclear fleet. Moreover, all nuclear reactors belonging to the former East Germany that are either in operation or under construction were shut down during the reunification of Germany in 1990 as a result of their failure to meet appropriate safety standards.

In the **United Kingdom**, as in France or Japan, the government launched an ambitious nuclear power program in the 1950's. From being a country reliant on importation of fossil resources, it wanted to develop a secure source of energy. The United Kingdom today therefore appears to be one of the longest standing nuclear operators.

Considering nuclear energy to be the technology of the future, the British government had encouraged the setting up of several industrial groups. However, technical problems encountered with the AGR reactor led to the abandonment of that national option in 1981. Later, the discovery of large hydrocarbon deposits in the North Sea and the full privatisation of the electricity sector caused the United Kingdom to look again at the economic advantages provided by nuclear energy, and a new reactor was commissioned during the nineties (Sizewell, in October 1995).

(1) See details of that agreement in annex 2.

With an overall capacity of 13 GWe, the nuclear fleet comprises 35 reactors : 20 of them, the oldest ones built on the Magnox (MGUNGG) design were entrusted to a public company, British Nuclear Fuels Limited (BNFL) – they were commissioned between 1956 and 1972 (mean age 33 years) ; the others, 14 AGR reactors commissioned between 1976 and 1989 (mean age of 17 years) and a PWR installed in Sizewell with a new capacity of 1 188 MWe, were entrusted to British Energy (BE). BE was successfully privatised in 1996, whereas BNFL (still in anticipation of the continually postponed privatisation) manages the old reactors which will soon be reaching the end of their lifetime. BE is expected to extend the service life of its power plants for the maximum duration.

Russia and Eastern Europe currently represent almost 13 % of the installed nuclear capacity in the world, i.e. a capacity of 45 GWe shared between 67 reactors. Although the first electricity produced in a nuclear power plant goes back a long way (1954), most of the plants currently working in this country were built during the Soviet period starting in 1973. Many plants saw industrial commissioning in the nineties, so the reactors are still relatively young (average age 15 years) however the safety standards applicable to those reactors are far from satisfactory according to Western standards.

Russia has tried a number of systems and today uses mostly RBMK (10 GWe) reactors, one rapid neutron reactor (560 GWe) and VVER (9 GWe) reactors. Twelve new nuclear plants are apparently under construction, despite facing financial complications and safety problems. The priority at the moment for Minatom, Russia's nuclear operator, is that of bringing its reactors up to Western safety standards [1] and therefore of finding the corresponding financial backing.

At the gates of the European Union there are several countries with a fleet of nuclear plants generating the major portion of their electricity supply, namely Bulgaria (41.5 % of electricity production in 1999), Hungary (38 %), Lithuania (73 %), the Czech Republic (21 %), Romania (10 %), Slovakia (45 %) and Slovenia (23 %).

The reactors in those fleets are relatively young, apart from two Bulgarian reactors commissioned in 1974 and 1975 : the reactors were commissioned in 1981 and 1993 in Bulgaria, 1983 and 1987 in Hungary, 1985 and 1989 in Lithuania, 1985 and 1987 in the Czech Republic, 1980 to 2000 in Slovakia,

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(1) The RBMK nuclear plants, for instance, have no containment building.

1983 in Slovenia and 1996 in Romania. Most of those reactors reveal the same shortfalls in safety as those discovered on the Russian reactors.

Far away from Europe, **Asia** seems to be potentially the most dynamic region in the world as regards the development of nuclear power production.

The **Asian countries** will be facing a huge demand for electricity to meet the needs of the rapid economic development and fast growing population : the demand for electricity, which grew by 8 to 9 % per annum over the period 1971-1995, whether in China, East Asia or South Asia, could continue by as much as 5 to 6 % annually between now and 2020, according to a recent survey by the International Energy Agency. In those conditions, nuclear energy will be included in the future electricity production, partly with the aim of diversification, partly because it enables developing sizeable capacities in the places where the demand for electricity is highest.

The economic crisis that hit Asia so hard seems only to have delayed the programmes ; apparently [1] there are 24 reactors currently being built in Asia (19.5 GWe) and 4 more are on order, figures comparable to the current installed capacity in that region, estimated at 65 GWe (91 reactors). Out of those 24 reactors, 2 are being built in Taiwan, which has 6 others already in operation. For this country, however, changes in the political situation may result in a review of the current programme.

In **Japan**, nuclear energy has been regarded as a major asset alongside coal and natural gas, and essential to the diversification of power production in a country lacking its own supply of natural resources. The development of nuclear energy in Japan therefore benefited from strong and sustained political backing, despite very considerable opposition locally in the preliminary phase prior to construction. Japan currently operates a fairly young fleet of 53 reactors, amounting to a capacity of 43.5 GWe, almost 60 % of which are under 15 years old. Together, those power plants supplied 36 % of Japanese electricity demand in 1999.

The most recent long-term Japanese nuclear programme launched in June 1994 forecast an increase in installed capacity up to 70.5 GWe in 2010 and 100 GWe by the 2030 time frame. Reviewed on a five-yearly basis, the programme will be noticeably downsized partly as a result of a lack of public confidence after

(1) The last ELECNUC publication, copied in the previous table, still showed the situation at end 1999 as 27 reactors under construction and 9 on order, and did not yet include all the revisions that have taken place in recent months.

JCO/Tokai Mura incident and some earlier ones, and also to adapt to a significant downturn in prospects for economic growth and therefore the demand for electricity. Nevertheless, four reactors are in the process of construction at the moment and six more should be launched by 2010.

Furthermore, in the case of Japan, the geographical nature of the country and its extremely dense population restricts the number of available locations for the power plants. Therefore, they have to develop as few sites as possible, and the different Japanese utilities operating nuclear reactors are considering extending the lifetime of the current plants to 60 years, by conducting extensive rehabilitation projects.

China is where the greatest development potential lies, even if China does not intend nuclear energy to displace their coal-fired production units. The first nuclear-based power generation took place in China in 1991 in the Quinshan-1 reactor (a 280 MWe PWR reactor of Chinese design). There are two reactors in operation today that were commissioned industrially in 1994 and nine reactors under construction (anticipated commissioning date some time between 2001 and 2005). The Chinese policy consists of trying out several foreign systems before choosing the most suitable and at the same time maximising the technology transfers. Some long-term projects have been announced, taking the total capacity to 22 GWe with 25 reactors likely to be built before 2015.

Some other countries have few or no nuclear reactors, to date. That group includes :

- two countries that used nuclear energy during a period of their history but abandoned it for political reasons (for instance, Italy [1] in 1988) or for economic reasons (Kazakhstan in 1999) ;
- countries with little demand for electricity alongside a small population and sluggish economy ;

(1) Italy had 3 reactors in operation (1 300 MWe) and 7 reactors on order (5 850 MWe) at the time of the 1987 referendum that led to the decision to abandon nuclear power generation.

- countries in which the small population density does not justify the implementation of large capacity power plants [1] ;
- countries with ample fossil fuel resources, and who therefore use those fuels before any others to develop their power plants, in an effort to preserve their foreign trade balance.

  Some countries with their own fossil resources are currently showing an interest in nuclear energy, out of the desire for diversification. Mexico, for instance, whose first nuclear plant started up in 1990 ; and Argentina, Brazil or India also. That evolution might continue even if nuclear energy is used for only a modest share of the electricity demand in those countries.

1.2. Public research and development (R & D) programmes

For many countries, the scope of public research & development programmes in the domain of energy, and the percentage funds allocated to nuclear energy out of the overall public budget destined for the energy sector may be an indicator of the long-term future of nuclear power in those countries.

To gain an idea of the way those programmes are moving, we used data published by the IAE, knowing full well that their approach looks at only part of the picture. Their survey particularly excludes any research done by industry – and does not automatically provide comparative information, since the notion of public expenditure often differs from one country to another and even within a country with respect to the different energy sources. Furthermore, not all informations on public spending on R & D has been communicated to the IAE

According to those data, the largest part of public R & D efforts [2] relating to energy technologies is concentrated in a small number of countries : Japan and the United States in particular, at the end of the nineties, together represented 75 % of the entire budget allocated by all of the IAE countries to R & D on energy (Japan alone accounted for 50 %). However, these expenditures have evolved very differently over the past fifteen years : for instance between the Japan, whose budget remained stable over the period, and the United States

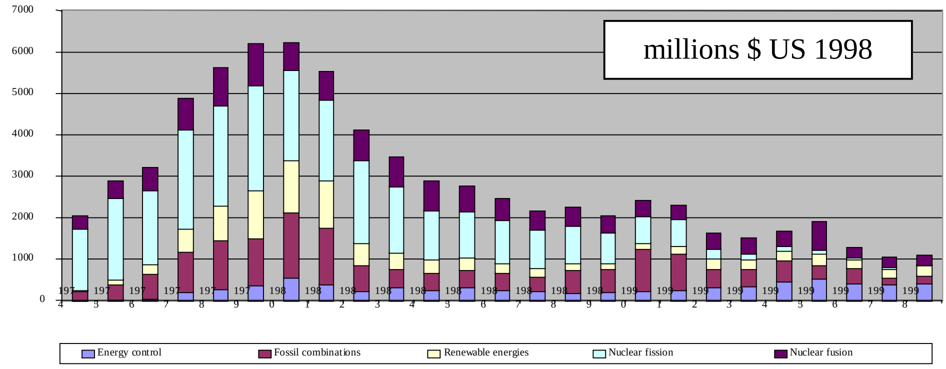
(1) There may possibly, in this case, be a market for HTR type power plants of reduced power like the one currently being developed in South Africa.

(2) The mixed nature of these data particularly does not enable us to establish links between the research, technologies and investments and to specify the research lines that may have been preferred in the different countries and weighed on the investment choices.

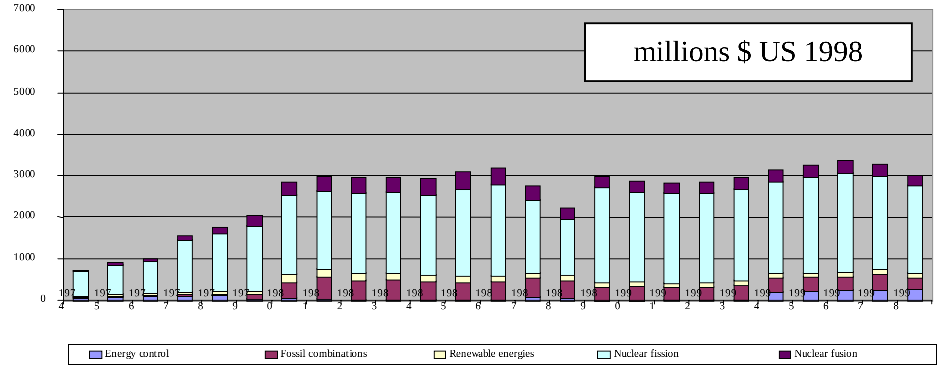
whose budget was divided by 3.5 between 1980 and 1998. In 1998, the public budgets spent on energy in the United States amounted to 64 % of the sums spent in Japan.

The following graphs illustrate the evolution of the share of nuclear energy in the public R & D budgets allocated to energy over the period 1974 to 1998 in the United States and in France.

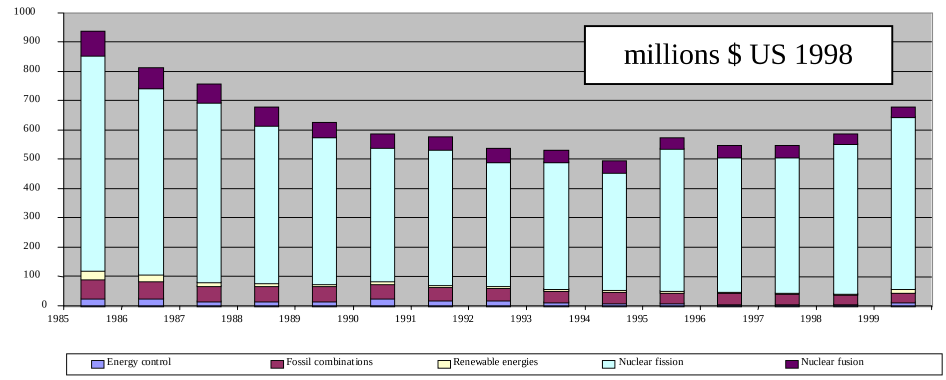
Energy : public R & D budgets in the United States



Energy : public R & D budgets in Japan



Energy : public R & D budgets in France



Source : AIE

- **Japan** allocates almost three-quarters of the public R & D budgets to the domain of nuclear energy and thus in 1997 concentrated 65 % of the overall public budgets of the AIE countries earmarked for nuclear energy. Those budgets have dwindled regularly since the record high of 1996, with a 13 % reduction for nuclear energy whereas the R & D budgets for energy overall dropped by only 11 %.

- **The United State's contribution** to the overall public expenditure assigned by the AIE countries to R & D on nuclear energy has seen a considerable decline (from 11.3 % in 1995 to 7.2 % in 1997). The vast majority of the public effort on R & D is currently concentrated on controlling the demand for energy (421 millions US $98 in 1998 compared with 237 millions for nuclear industry).

- The **French** public budgets assigned to R & D for the nuclear industry have exceeded the American budgets since 1995 and the gap continues to widen. They represented 13 % of the overall budget of the AIE countries for R & D into nuclear industry in 1997. At the same time, the public R & D budgets in the field of energy control remained negligible.

As for R & D expenditures by the electrical contractors, even if we lack exhaustive data on the amounts, the partial data available show that they will evolve alongside and driven by public expenditures.

Rather than putting in place public R & D programmes, some countries prefer to purchase R & D from Western countries by means of technology transfer. China, for instance, used this method, by choosing Western companies to build its nuclear reactors, although it fully intended at a later date to develop its own system based on the acquired technologies. South Korea likewise, which developed its nuclear industry is using to a great extent imported technologies and indeed continues to progress in this domain with the help of Western companies.

2. The emergence of environmental problems on a global scale

Among the problems relating to the development of energy systems, a number of risks, due to their geographical scale or far-reaching impact in terms of time, pose problems for all of humankind across the globe. Those risks essentially impact the management of the resources (depletion of fossil and fissile resources, competition as regards soil use), safety (the threat of major disasters, nuclear proliferation) and the accumulation of by-products (greenhouse effect gases, nuclear waste).

Those risks are not mutually independent : for instance, to fight global warming, we might consider using less fossil energy resources. In doing that we merely postpone the depletion of the resources as we slow down the emissions of greenhouse gases responsible for that warming. But if, in order to meet the demand for electricity, we considerably increase our use of nuclear energy or renewable energy sources, we thereby increase in similar proportion, the risks associated with nuclear energy or competing land use. It is therefore essential, when defining a strategy for sustainable development, to bear in mind the inevitable inter-dependence of the medium and long-term risks.

That comment appears to be particularly well founded at this moment in time, as we become increasingly aware, on the international level, of the problems raised by the greenhouse effect. The fear of an increase in global warning might, indeed, at first sight, cause us to prefer nuclear energy where greenhouse gas emissions are negligible. Thus, using nuclear energy is sometimes today presented as one of the principal tools for fighting the greenhouse effect – and the debate [1] widens internationally on the legitimacy of the argument. One cannot, however, examine the position of nuclear energy in the complex problems of combating the greenhouse effect without first asking whether the same caution is being exercised with respect to the long-term risks of the nuclear industry, in particular as regards the quantity and quality of the waste produced.

The extent of knowledge and technical control of the risks (greenhouse effect as well as risks associated with the nuclear industry) varies. The diversity of the processes arising out of that knowledge is, to some extent, unavoidable. We do, however, consider that the same attention should be brought to bear on all of those risks : the principles of caution or prevention can be developed individually in each sector, however they can be conceived only through a global approach.

Generally, to take into account the prevention of the risks to the environment associated with the different energy systems, the economist has to choose between two methods :

(1) People particularly wonder whether or not it is advantageous to include nuclear projects in the flexibility mechanisms.

- A « cost-benefits » method that consists of surveying and evaluating on the one hand the damage associated with the risk incurred by the emissions and discharges and, on the other hand, the possible actions that can be taken to reduce those same emissions or discharges. Comparison of the marginal costs of the damage and of the reductions in emissions or discharges enables us to find the right economic balance that will assure an economic advantage to be drawn from the measures taken. Estimation of the damage, however, is fraught with many uncertainties ;
- A « cost-effectiveness » method that aims more modestly to optimise the cost of the measures to be adopted to reach a given objective for the reduction of the emissions or discharges. In this case, it is no longer necessary to name the damage, their scope of action and the cost of reparation. We look instead at the causes, at what is responsible for each (the different greenhouse effect gases, the different types of nuclear waste, etc.) and we seek to minimise the costs involved in reducing their emission to a given target. The value obtained thus corresponds to the marginal cost of decontamination or the reduction in emissions and is no longer tied to the hazier notion of damage. That is, we admit that we are unable, at this early stage, to allocate an accurate cost and know the full scope of measures to be taken, but that does not prevent us from taking the first steps towards action.

When we do not know how to estimate the damages related to the environmental risks associated with the different energy systems, we cannot use the “cost-benefits” method to prevent those risks. In these conditions, therefore, international opinion favours the use of the « cost-effectiveness » method. This is the case with the greenhouse effect, when we develop programmes aimed at reducing C02 emissions, and with nuclear waste when we develop programmes to reduce the volume of long-life high-level radwaste.

2.1. International nature of the CO_2 problem : the climate conference

In recent times we have seen an intensification of discussions on an international basis to achieve a general consensus on the measures to be taken to prevent global warming. The Kyoto negotiations marked a first, important step in that direction with the industrialised countries committing to a 5.2 % reduction of the emissions in 2010 as compared to 1990, whereas the trend would otherwise be more towards an increase of 10 to 15 % over the same period.

Greenhouse effect : a matter for international negotiation

In view of the major uncertainties concerning both the precise nature, geography and magnitude of the repercussions of climate change attributable to the anthropogenic increase in greenhouse gas (GHG) emissions, the international community meeting at the United Nations Framework Convention on Climate Change (UNFCCC) jointly committed to a policy of prevention that would consist of reducing the flow of GHG emissions throughout the world by the year 2010, with the longer term prospect of stabilising concentrations of GEG at a level that will « *prevent dangerous anthropogenic interference with the climate system. Such a level should be achieve within a time frame sufficient to enable ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner*».

The Kyoto protocol specified the chosen method for action. Two methods of action were in fact available :

- imposing an obligation for the provision of resources upon the signatory parties to the protocol, for instance by introducing a specific system of taxation on the emission of greenhouse gases. The disadvantage of that method resides in the inability to determine *ahead of time* any quantitative result that can be expected from the economic constraint applied under that system ;
- imposing upon the signatory countries an obligation of performance, for instance by setting quotas for the emissions over a given time frame.

The latter method was finally chosen. Those quotas, applicable solely to those countries listed in annex 1 (OECD countries and countries belonging to the former Soviet block) countries) were defined in reference to the GHG emissions of 1990 in each of the countries, in the form of a percentage reduction to be achieved by 2010 (5.2 % for all countries listed in annex 1, 1.8 % for Europe, 5 % for the United States, 0 % for Russia, etc.).

To facilitate implementation of the agreement, the Kyoto protocol stipulates various mechanisms to allow a certain degree of flexibility :

- a market of rights (or permits) negotiable between signatory parties to the Kyoto protocol (countries listed in Annex 1) ;

- joint application between the parties listed in Annex 1. It may be less costly for a developed (Annex 1) country to reduce its C02 emissions by investing in another Annex

1 country rather than investing at home, which is the solution generally preferred by all ;

- the mechanism of home development, which allows an Annex 1 country to help a developing country achieve sustainable development while simultaneously fulfilling its own commitment for the reduction of emissions.

Those different market mechanisms are all aimed at orienting the investment options towards economic projects to reduce greenhouse gases at minimal cost.

The international community should not await a precise description of the causes and costs involved in mitigating the adverse effects of global warming before taking precautionary measures to control the increase in emissions [1]. It encouraged in some cases and in others imposed a quantitative commitment on limitation of the emissions, and considered introducing mechanisms for a more flexible approach.

2.2. Nuclear risks

Generating electricity using nuclear energy involves specific risks related to the radioactivity of the materials consumed and those generated. Those risks can be divided basically into three types :

- risks of personal exposure or environmental contamination as a result of operations (in an accident situation, of course, but also during normal, or routine operations) ;
- risks related to radwaste of various types produced by the nuclear industry ;
- lastly, risks of proliferation associated with the development of nuclear weapons.

If the risk of proliferation, which by its nature transcends national boundaries, rapidly became a topic for negotiation at international level, the other risks, whether relating to the safety of the installations or waste processing, were first considered in their national contexts. Broader discussion has now been engaged internationally on each of the above problems : beyond the Non-Proliferation

(1) In our report, we chose the greenhouse gas emissions directly issuing from the combustion of fossil fuels and estimated the emissions given off during their processing or transportation, using variable ratios depending on the fuel used.

Treaty [1] (NPT) which supposes a commitment on the part of a number of countries on matters pertaining to nuclear weapons, the international institutions are now looking at other topics, such as safety ; no international agreement has been reached as yet regarding the problem of radioactive waste.

International agreements in the nuclear sector

The Non-Proliferation Treaty is an international instrument universally aimed at combating proliferation. At present, 187 States have ratified the treaty and only four States, three of which – India, Israel and Pakistan - are known to have a nuclear capability, remain outside of the Treaty.

Furthermore, the specific international agreements to which France is a Party have been negotiated in different domains, particularly in the domain of safety, which includes the management of spent fuels and the management of radioactive waste :

1 – Safety

- The agreement on ***rapid notification in the event of a nuclear accident*** (brought into effect for France on 6/04/89).
- The agreement on ***provision of assistance in the event of a nuclear accident*** or a radiological emergency (also brought into effect for France on 06/04/89).
- The agreement on ***nuclear safety*** (in effect for France since 14/10/96).
- The joint agreement on ***management of spent fuel and the management of radioactive waste*** (law passed on 03/03/2000 but not yet applicable).

2 – Security / international transportation

- The agreement on the ***physical protection of nuclear materials*** (brought into effect for France on 06/10/1991).

3 – Third party liability

- The Paris agreement on ***third party liability in the domain of nuclear energy*** (brought into effect in France on 01/04/68) (+ following texts).
- The agreement relative to ***third party liability in the domain of the maritime transportation of nuclear materials*** (in effect for France since 15/07/75).

4 – Environment

- The London convention on ***the prevention of pollution resulting from the dumping of waste at sea*** (in effect for France since 05/03/77).
- The ***OSPAR*** convention (in effect for France since 25/03/98).

(1) See presentation of the Non-Proliferation Treaty in annex 4.

Given that the debate in France and more generally in Europe, focuses on problems relating to the front end of the nuclear cycle (radioactive discharges from nuclear installations and reprocessing plants in particular) and the future of very long-life radwaste, in our report we concentrate on those questions rather than on a detailed study of international problems relating to the safety of nuclear installations or risks of proliferation. However, some indications as to the current status of international debate on those matters are given (see annex).

Waste [1] (defined in Chapter I as « *those matters abandoned on completion of the nuclear cycle, perhaps only for an interim period, depending on the technical and economic conditions at the time* ») materials are stored while awaiting the construction of installations for their definitive disposal, or perhaps in some cases, while awaiting a decision on such storage. This is the case in particular with the more radioactive long-life categories of waste, which are a major concern of researchers, decision-makers and citizens alike.

Nuclear waste and effluent disposal is basically at the current time a matter for national sovereignty, with the noteworthy exception of some international commitments made on pollution at sea, such as :

- the London convention on the prevention of pollution as a result of the dumping of waste at sea ;
- the OSPAR convention for the protection of the marine environment of the North East Atlantic – which in particular sets the principle prohibiting the dumping of substances (waste) including low and medium level radioactive waste and discusses the prevention and prohibition of pollution derived from telluric sources.

It was followed by policy undertakings made within the framework of the OSPAR convention whose members met in Sintra on July 22nd and 23rd 1998, a meeting which led to the adoption of several strategies, one of which concerning radioactive substances. That strategy stipulates that by the 2020 deadline « the Commission will do its utmost to ensure that discharges, emissions and losses of radioactive substances shall be reduced to levels where

(1) Our definition of radioactive wastes differs slightly from that of the IAEA, which gives the following definition : « …a radioactive waste can be defined as a material that contains or is contaminated by radionuclides at concentrations or activities higher than the thresholds for release established by the regulatory authorities, and for which no use is envisioned ».

the additional concentrations in the marine environment above historic levels resulting from such discharges, emissions and losses are close to zero ».

Under the influence of the thinking and conceptual progress proposed in the combat against global warming (international conventions, principle of precaution) and the major problems encountered by the international community with the civilian nuclear energy of countries belonging to the former Soviet block, there is an increasingly urgent push for problems of waste to be dealt with on an international basis.

Concerning the type of waste that poses the greatest problems in terms of acceptability –(long-life and high-level radioactive waste) the question arises whether, for instance, discussion on similar lines to that undertaken on the limitation of greenhouse gas emissions can be engaged concerning limitation of long-life radwaste stocks. Despite distinct differences between the two matters, several arguments plead in favour of this approach :

- straight away, the problem concerns the very long term and implies making choices for future generations, knowing that when we choose to follow a particular avenue we necessarily shut off other paths ;
- the state of our scientific knowledge does not always enable us to quantify the risks we run. Hence the need to carefully separate those risks we can protect against (through insurance and the futures market) from those risks where the decision-maker has to act with uncertainty as to the future.

Lastly, the performances of nuclear energy with regard to greenhouse gases make it a potentially strong tool for reducing the emissions of such gases. Without a mechanism equivalent to the emission quotas, the substitution of nuclear energy for fossil energy sources could possibly result in a massive increase in the volume of all kinds of waste, including long-life waste (not to mention increased risks of proliferation).

This is why, in the following chapter, we decided to accompany each scenario with a presentation of the flows and incremented totals of the greenhouse gases and wastes produced up until the cut-off date, taking care to define precisely the kind of waste in each of the scenarios, as each of them are likely to impact the environment.

The particular attention we felt should be paid to the trickier problem of high-level long-life waste (more than several hundred years) caused us clearly to specify the consequences of the build-up of stocks of plutonium, minor actinides and very long life fission products in the different scenarios.

2.3. First attempts to integrate environmental costs into electricity costs

Since the end of the nineties, problems relating to the evaluation or utilisation in the decision-making process of the external costs [1] involved in electricity production have been a topic of interest in the energy sector, in industrialised countries. In those countries, the share-out of production between the different energy sources is a matter that arises at different decision levels : federal, national or local. In particular, when defining the contribution of nuclear energy in the future (United Kingdom, Switzerland) or the conditions for distinctly increasing the share of renewable energies (Germany, United States).

In Germany – One of the leading empirical studies on the estimation of damages related to electricity production (using fossil, nuclear or renewable energy sources) was conducted in 1988 in Germany, by O. Hohmeyer in his survey « Social costs of energy consumption ». That studied had enormous impact, for it suggested that introducing the factor of the external costs (social costs not directly factored into the contract) might make renewable energies more competitive than coal or nuclear energy for the generation of electricity. The approach was intended to be all-encompassing, taking into consideration the impact on health, crop harvests, employment, etc. Certainly the hypotheses could be challenged (the majority of atmospheric pollution was arbitrarily attributed to coal-fired power plants, the allocation of public R & D budgets was often arbitrary, etc.) however, that study had the merit that it drew attention to the need to factor into the economic calculations the more or less quantifiable indirect costs involved in the individual electricity production systems.

In the United States – A similar, although somewhat less ambitious approach was adopted following Ottinger's work, in 1990. Electric utilities from several States (New York, California, Massachusetts, Nevada, Oregon, Wisconsin) made efforts to factor environmental costs into the calculation of the cost price of the kilowatt-hour of electricity (according to the so-called "add-ons" logic). Starting in 1993, many of the regulatory commissions forced the electric utilities to perform such calculations. However, the process came up against a number of obstacles, due to difficulties in evaluating certain costs and the

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(1) See annex 7.

perverse effects that such an approach could give rise to (some utilities tended to extend the service life of older, polluting installations rather than to build new infrastructures due to the fact that those external factors [1] were applicable only to new installations). Also worth noting, the on-going liberalisation process that in the early days increased competition between firms, tended to cause those same firms, later on, to relegate environmental concerns to the background.

In Europe – without doubt, the most serious reference on the external factors associated with electricity production is the ExternE study conducted by the European Commission in 1995 (and updated in 1997-1998). The study used the following approach :

- ***stage one*** quantified the physical phenomena relating to the construction and operation of a power plant (or fleet of plants) ;

- ***stage two*** evaluated the environmental impacts of the various possible risks and emissions from a "physical" perspective : diseases, accidents, fatalities, effects on the food chain, on harvests, on land use, on the greenhouse effect, etc. Those impacts were evaluated in short, medium and long-term probabilistic terms ;

- ***stage three*** "monetized" those "physical" values (number of fatalities, working days lost, etc.). The study was based, naturally, on numerous hypotheses, such as the price put on a human life, the value of land, lost harvest or destroyed landscapes. Furthermore a discount rate had to be determined that would reflect society's preference for now rather than later.

As local environmental damages are specific to a particular site, it was important to find a site that was "representative" of an analysed fleet of power plants. For the fossil-fired plants, examples were drawn from Germany and the United Kingdom (coal, diesel, gas). For nuclear energy, the example was taken from France. For renewable energies (wind-driven, biomass and hydro power) examples were drawn from the United Kingdom and Norway. Overall, the results highlighted very big disparities, depending on the sites chosen for each system. The most recent version of the ExternE study (1998) is not limited to a few representative sites but looks across the board at very different situations in

(1) In any case, at that time, the American operators were operating in a monopoly system and passing on all of the costs with the agreement of the control bodies in the individual States.

the 15 countries of the European Union. The conclusion is that it is difficult to decide on a mean figure, because of the sensitivity of the result to the conditions at the outset, which can be observed. Certainly, the study shows strong trends : coal (*and to an even greater extent,* lignite) and to a lesser extent fuel result in higher external costs than natural gas or hydropower. The external costs with nuclear energy are relatively modest, however that is largely due to the study method used : the study leaves out long-term waste management related costs due to the lack of scientific data on the subject. The study does, however, take into account the costs relating to accidents (plant operation, fuel transportation, etc.) and the short and medium term storage of the waste. It pays more attention to the impact on health of the various emissions.

Moreover, concerning the nuclear system, the ExternE study looks principally at the physical impacts on the human population (effects on health, fatalities as a result of accidents, emissions), but the analysis is conducted over a rather limited time frame, and using a probabilistic approach. Hypotheses had to be made on models of the dispersal of radionuclides, and the dose-response functions used are based on epidemiological studies that attempt to establish a correlation between exposure to the individual pollutants and the effects on health in the populations exposed to them. Neither is the switch to a monetized evaluation achieved without difficulty. The economic cost of the disease was generally measured by totalling the medical costs and the costs of lost workdays. The cost of fatality was even more difficult to determine.

Having accepted the idea of attributing a statistical value to human life (that of a "statistically anonymous citizen") one then has to fix an amount for that statistical value. In the case of ExternE 1995, that value was an arithmetic average of estimates based on the consent to pay individuals to avoid a risk of fatal accident on the work place. The approach in terms of human capital (discounted value of the probable future income of an individual) was discarded. The second (1998) version of ExternE preferred to use as a reference the value of a lost year.

Analysis of the results shows that it is the adverse effects on public health that largely condition the hierarchy between the various electricity production site. In reality, those are not the only damages to be considered, yet the Commission's study in fact favoured that aspect. In the case of nuclear energy, one should also note that the monetization of the future potential damages poses in a particular acute manner, the delicate question of which discount rate to choose. The ExternE teams avoided that difficulty by adopting three different rates depending on the simulations (0 %, 3 % and 10 %).

The usefulness of that study is that it proposes a method to evaluate the external factors and shows us that those factors can be factored into the decision process. Its results are without a doubt much more reliable for electricity produced using fossil fuels than the electricity of nuclear origin. The study, as the authors freely admit, glosses fairly rapidly over the problem of the long-term management of radioactive waste.

3. Spent fuel management options taken up by the main nuclear countries

On this matter, international co-operation works only on the scientific and technical problems. Therefore, the options taken up by the different countries is considered by each nuclear country as a choice of technique implying a decision at the national level rather than a choice imposed under a global policy.

Three spent fuels management methods [1] are currently used or are under consideration in the world : reprocessing-recycle, which consists of separating and recycling the spent fuel, re-usable uranium and plutonium and conditioning the fission products and minor actinides for disposal at a later date ; the direct disposal of the spent fuels in deep geological repositories after a period of interim storage to allow them to cool down ; interim storage to enable postponing the decision.

The reprocessing of spent fuels historically and industrially cannot be dissociated from the consideration of plutonium. Plutonium has always, since the very first developments of nuclear energy, been an integral part of any strategy for the use of fissile materials. The first reprocessing installations were implemented for military purposes.

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(1) We use the terms « spent fuels » and « irradiated fuels » with the same meaning.

Respective advantages of reprocessing and direct disposal

Reprocessing

Countries that opted for the « closed cycle » (reprocessing-recycle) often did so to ensure an independent energy supply in the event of a shortage of fissile materials that would drive up the cost of uranium. Reprocessing moreover has quadruple benefits : it reduces the volume of radwaste, thereby facilitating their management, it eliminates the plutonium (which can be recycled as a fuel) thereby reducing the potential toxicity of the ultimate waste, and also reduces the costs as some of the recycled products (uranium 235 and plutonium) can be re-used and lastly, it enables concentrating and conditioning the ultimate high-level long-life waste in molds designed to assure their extremely durable confinement. In fact, however, in the current state of the techniques, for economic reasons reprocessing is not always pursued for more than one cycle, which means that in addition to the disposal of the ultimate waste, one has to consider the interim storage or direct disposal of large quantities of spent fuel with a high plutonium content.

Supporters of the « open cycle » (direct disposal without recycling) refute those benefits, insisting on the complexity of the cycle in the reprocessing-recycle option, a complexity that can be seen in the increased number of handling operations and therefore increased number of risks. They comment that it is difficult to recycle the plutonium more than once which, as it is becoming increasingly rich in isotope pairs, becomes less and less fissile in front of thermal neutrons, which requires in increase in its fissil content with each new recycling process [1]. In view of the high radiotoxicity of plutonium, its elimination from the waste through reprocessing greatly reduces the toxicity of the so-called « ultimate » waste (by a factor of approximately 10). The volume of the ultimate waste for storage is also reduced, by a factor of 5. However, the risk of nuclear proliferation is increased since the plutonium was « separated » from the other waste [2]. Moreover, nothing proves that handling a variety of different types of waste is much easier than managing a single category of waste. The diversification of the waste has advantages but can also involve drawbacks, for the risks are often inter-dependent.

(1) That limitation could nevertheless be lifted with the new fuel types which enable multiple recycling in light water reactors and, in the longer term, in a new generation of reactors optimised to achieve savings in natural resources and that have a high capacity for burning plutonium and long-life wastes.
(2) To counter this risk, the plutonium (energy source) is sent to France in the fuel and recycled, the tonnages reprocessed and recycled in a reactor always assuring that the flows are equals, while minimising the quantity of separated plutonium strictly to the recoverable scrap that can be used to manufacture MOX fuel.

Direct disposal

Direct disposal of the fuels requires prior storage for a minimum of 50 years to enable the decay time of the highly radioactive short-lived elements (the so-called cooling period). Various solutions are used for that interim storage : pools, surface packing, etc. Lastly, a site has to be found for definitive disposal. No country has so far come up with a definitive solution for direct disposal. The main issue is the reversibility or not of the disposal solutions. It is perhaps thought that scientific progress will one day enable the re-use of those wastes in better conditions than the current reprocessing-recycle solution, or even their transmutation into much shorter lived elements. If that were the case, then the disposal solution should certainly not be irreversible. However, for the long-life elements (up to several thousands of years) it is important to find deep repositories to house the waste well beyond the memory of the populations. It is fairly improbable that it will be possible to ensure reliable protection of the surface storage site for centuries to come. Hence the search for safe geological formations (salt, clay, granite, volcanic rocks or even the ocean depths). Some people are opposed to deep storage as they consider it unlikely that confinement can be guaranteed over such a long time frame. The least poor solution, paradoxically, is surface storage for it is easier to monitor.

In all, given the current conditions as regards uranium prices, the reprocessing-recycle strategy plus storage of the ultimate waste, though developed in a context in which the uranium ore was expected to become rare and expensive, now proves to be more expensive than direct disposal. That strategy nevertheless results in a reduced volume of ultimate waste for storage and represents an immediate saving in terms of resources (recycling of fissile materials) and a reserve of potential resources for the future (use of the fertile materials) and thereby opens up an array of options.

Then, in the seventies, when optimistic international forecasts encouraged a rapid development of nuclear energy, a big supergenerator programme was considered in view of the high price of uranium, the feared risk of shortage and the desire to increase the energy independence of countries deprived of fossil resources of their own (France, Japan, etc.). To supply the supergenerators it was decided to develop mass reprocessing of the spent fuels produced in the reactors.

In France, for instance, that policy resulted in the industrial commissioning in 1958 of the first Plutonium factory (UP1 or Usine Plutonium n° 1) in Marcoule, with an annual capacity of 400 tonnes of fuels from gas-graphite (UNGG) reactors. The UP1 plant will have been in operation almost 40 years by the end of 1997. With the commissioning of the first civil electricity producing reactors in 1963, the matter of the future of those civil spent fuels arose, just when the start-up of the rapid neutron reactors programme (Rhapsody and Phoenix, commissioned in 1967 and 1973 respectively) required an available supply of plutonium. Construction of a second reprocessing plant (UP2) with a capacity of 800 tonnes a year of fuels from UNGG, was therefore undertaken, for commissioning in 1966. 1976 saw the commissioning of a workshop in UP2 to process 400 tonnes per annum of PWR fuels. In May 1981 the decision was made to build UP3 with an annual capacity of 800 tonnes which was theoretically intended to reprocess over a ten-year period spent fuels from PWR and BWR abroad as well as fuel from EDF power plants. In 1985 it was decided to build UP2-800 with an annual capacity of 800 tonnes solely dedicated to reprocessing spent fuel from EDF's pressurised water reactors.

Among the countries practising reprocessing on their home territory, alongside France we have : the **United Kingdom** which opted for reprocessing for its first generation of fuels in the sixties ; **Russia** which since the beginning of the nuclear era, has been reprocessing all of the spent fuels from the Eastern European countries on its territory ; **Japan** which from the start had an all-reprocessing policy alongside an extensive supergenerators programme, but which has only one reprocessing plant on its territory, Tokai Mura, with a capacity of 90 tonnes per year and another plant currently being built with a capacity of 800 tonnes per year (Rokkasho Mura) which could be in operation shortly after 2005.

Other countries such as **Germany**, **Belgium**, the **Netherlands** or **Switzerland** prefer to send their fuels abroad to be reprocessed.

The international context with respect to reprocessing has changed a lot in recent years. Gradually, most foreign electric utilities have limited and in some cases withdrawn from their commitments. Thus **Sweden** was the first country to officially abandon reprocessing. **Germany**, after having lifted its obligation to reprocess in 1994, allowed its electric utilities to choose between reprocessing and direct disposal and then just prior to commissioning the Kalkar supergenerator, abandoned in succession the Wackersdorf reprocessing plant and a new MOX manufacturing facility (the size of Melox) in Hanau. **Belgium** [1] in 1993 pronounced a five-year moratory on the fulfilment of any reprocessing contracts and effectively cancelled its post-2000 reprocessing contracts in December 1998. **Great Britain** which very early has showed an interest in both

(1) The Belgian company FBFC manufactures almost 350 tonnes of fuel assemblies every year and was the leading producer of MOX fuel, first manufactured in Dessel in 1973 (the plant currently has a capacity of 35 tonnes/year). A national organisation, the ONDRAF is responsible for elaborating radioactive waste management projects and has set up a deep underground research laboratory for the geological storage of waste. That laboratory is now in operation, in Mol.

military and civil plutonium for the same reasons as France, devised a similar programme – now strongly challenged. British Energy, the British nuclear utility, as late as last March, in the face of technical problems encountered by BNFL (British Nuclear Fuels Limited) declared that it was considering abandoning reprocessing its spent fuels from AGR and PWR and would meanwhile content itself with storing those fuels in its installations. **Switzerland** has just drafted a bill that, if voted, foresees stopping reprocessing once all contracts signed prior to March 1st 2000 will have expired. Finally, the authorities in **Japan**, though officially their position on plutonium remains unchanged, have admitted that the three major accidents in Monju (1995) and Tokai Mura (1997 then 1999) have delayed and perhaps compromised the development of the initial programme. That programme scheduled the use of MOX fuels in two light water reactors between now and the end of 1999 before a progressive step up to 16 or 18 MOX units by the 2005 deadline. The falsification of data on MOX fuel at the BNFL reprocessing plant further complicated the situation.

In other countries, such as **Switzerland** the argument against reprocessing has developed around the risks relating to the transportation of spent fuels and waste and discharges into the water and air – during the reprocessing operation – of radioactive substances.

The international context, favourable to reprocessing towards the end of the seventies has now, at the end of the century, taken a U-turn. The main explanation for this is economic : forecasts, at the time when the development of nuclear electricity production and the volume of natural uranium deposits led to fears of a shortage or even depletion of the resource, hence the interest in a programme to re-use the plutonium contained in the spent fuels by reprocessing and using them in super generators. However, during the eighties, forecasts for the development of nuclear energy throughout the world proved highly exaggerated. The price of natural uranium, far from skyrocketing, plummeted to one-fourth of their value between the early eighties to the turn of the century.

In these conditions, the extra cost involved in reprocessing and manufacturing the MOX, compared to the direct manufacture of new UOX fuel through the enrichment of natural uranium is not offset by the saving in natural uranium due to use of the uranium and by the saving resulting from the reduction in the direct disposal of the ultimate waste. In other terms, this strategy represents for the electric utility, an increase in the cost of producing the kilowatt-hour of electricity, thus acting as a brake on their competitiveness, an aspect that is increasingly unfavourable in a newly liberalised market.

Some countries chose reprocessing for military needs : the United States for instance, to meet their needs for military quality plutonium, reprocessed 10,000 tonnes of slightly spent fuel and have ceased all production of that quality of plutonium since 1988 (they had halted the production of plutonium for civil supply in 1973) ; the same applies today to Israel, Pakistan, India and China. However, negotiations are shortly to start on a “cut-off” treaty prohibiting the production of fissile materials for explosive purposes. Should these negotiations be fruitful and enable the entry into effect of an international legal instrument, that would result in particular in those countries that have ratified the treaty shutting down their reprocessing plants for military uses and possible converting them to other uses (c.f. Savannah River in the United States). Moreover, if China, Israel and India have, like France, the Soviet Union and Great Britain already, based their nuclear arms programme on the production of military plutonium via the reprocessing of slightly spent fuels, the same is not true of Pakistan, which based its entire nuclear arms programme on highly enriched uranium and is only now starting to produce plutonium.

The table below gives an estimate at the end of 1997 of the volume of spent fuels produced by the main nuclear countries (excluding fuels reprocessed for military needs). That summary estimate is based on data obtained from COGEMA and the CEA/ELECNUC.

	Cumulative total, at end 97, of spent fuels discharged, in tonnes	**Current option for the back end of the cycle*** **	**Cumulative total, at end 97, of reprocessed spent fuels, in tonnes [1]**
United States	35 500 (REP + REB)	DD	200
France	13 360 (REP) 13 330(UNGG) RNR	R	11 900 (REP, REB) 13 330 (UNGG)*
Russia	3 400 (VVER) ? (RBMK	R + DD	3 000 ?
Japan	13 150 (REP + REB)	R	936
Germany	8 100 (REP + REB)	R + DD	85
Canada	24 000 (CANDU)	DD	0
United Kingdom	2 300 (AGR + REP) 45 000 (Magnox)**	R	500 ? 40 000 (Magnox)**
Ukraine	2550 ?		
Sweden	3 400 (REP + REB)	DD	0
Spain	2 150 (REP+BWR) ? (UNGG)	DD (R for UNGG)	0
Belgium	1 800 (REP + REB))	R	77
South Korea	1 850		0
Switzerland	1 400	R	0
Taiwan	1 850	?	0
Finland	1 220	DD	0
Rep. of China	170		
Others	?		?
Total	175 000 t.		70 000 t.

***** *UP2 has reprocessed 4 900 t. of UNGG fuels from 1966 to 1987. UP1 has reprocessed the additional UNGG fuels from EDF (and Vandellos) before definitively shutting down the plant (definitive shutdown in mid-1997), i.e. 13 330 tonnes.*

****** *Estimate*

**** R reprocessing*

DD direct disposal

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(1) The reprocessed quantities include fuels reprocessed for other countries (this above all concerns France, the United Kingdom and possibly Russia).

Some countries prefer the solution of direct disposal. That option sometimes accompanies a policy of abandoning nuclear energy, but more often reflects the determination not to isolate the plutonium for fear of proliferation.

The United States very clearly belongs to this latter group, even if they still have the largest stockpile of both separated (military plutonium) and plutonium in spent fuels. With the introduction of the Nuclear Waste Policy Act of 1982 (in an amendment dated 1987), the American Congress opted to pursue the storage of used fuels from power plants in geological repositories on a single site, Yucca Mountain in Nevada. Congress also delegated to the Department of Energy (DOE) the study, building, licensing and operation of the site in principle starting in January 1998, and operation was funded by a 0.1 cent per kWh tax paid by the operators.

In the face of opposition from the State of Nevada and having under-estimated the research programmes to be conducted, the deadline has not been met and now they are talking of 2010 at best. Three types of players are currently at loggerheads in the United States today, making it impossible to reach a solution : the operators, worrying as they see their storage pools gradually filling up and seeking compensation to fund a dry storage facility on site, are not hesitating to take out litigation against the DOE ; Congress, impelled by industry, is attempting in vain to get a bill passed to develop an interim storage facility near Yucca Mountain ; the Administration does not want to look at any other option than the geological repository yet at the same time does not want to go against local inhabitants by building a storage site before a definitive disposal site has been qualified.

For **Sweden**, its option of irreversible direct disposal was a decision for the end of the cycle to accompany the total abandonment of its nuclear programme by 2010.

Other countries prefer to postpone making a decision and wait for science to choose. They prefer to store the used fuels in the meantime, and perhaps reprocess them later once a new fuel and/or new reactor is developed, or to dispose of them in the best possible conditions. It may be considered, for instance, that it is better to store spent MOX today while awaiting the best solution to recycle the plutonium contained in it.

This brief overview of the international situation as regards the solutions taken up for the management of spent fuels, developed in Annex 3, shows that :

- direct disposal of spent fuels is one option several countries have taken up, but that no country has yet implemented ;

- the annual reprocessing capacities currently amount to approximately 33 % of the quantity of discharged fuels (3,000 t for a 9,000 t yield) and will be approximately 40 % after the Rokkasho Mura plant is commissioned ;

- advanced reprocessing (separation of the actinides : neptunium, americium and curium plus the long-life fission products in addition to the uranium and plutonium) and the transmutation of the minor actinides and long-life fission products into hybrid systems or dedicated reactors is currently being studied in many R & D programmes in Europe, Japan, the United States and Russia

Chapter 3

Technological forecasts for power use and generation

Before looking at the evolution of power generation technologies, it is important to give a brief overview of forecasts for the evolution of technologies for power use. Indeed, the anticipated performance improvements in the technologies that transform electric energy into a service for end users are a major determining factor in the evolution of demand for electric energy over the next 50 years. We will see below the influence of that demand on the options taken up for the future power plants.

1. Technologies for controlling electricity demand

The evolution of demand depends on a wide variety of parameters and circumstances. In our report, we chose two differentiated scenarios to reflect the demand for electricity up until 2050 [1], a first scenario in which demand reaches 720 TWh in 2050 and a second scenario in which the demand is 535 TWh, i.e. 26 % lower.

The demand for electric energy comes from both, captive uses, those for which electric energy has no competition, and non-captive uses. The non-captive category includes thermal uses of electricity (for heating, domestic hot water, air conditioning) and applications in the transportation sector. The demand for electric energy can be got undercontrol in all of the above uses.

1.1. The residential sector

Electricity is used in the residential sector essentially for heating (52 TWh), domestic hot water and cooking purposes (37 TWh), for lighting (10 TWh), cold (20 TWh) and other household appliances (13 TWh).

(1) Those scenarios are described in Chapter 4.

Technological evolutions in this sector include :

- enhanced equipment performances, with reduced consumption per unit for the same service rendered ;
- the introduction of new technologies for heating, cooking, washing or drying household linens, etc. ;
- the development of new electronic appliances (automation, domotics, etc.) for optimised management of the different appliances thereby reducing electricity demand and consumption.

The main difficulty in getting under control demand for electricity in the residential sector lies with the need for a general approach for each individual housing unit because of the variety of different uses involved.

If the structure of electricity demand in France is currently strongly marked by the development of electric heating in the residential and tertiary (services) sector, between now and the year 2050, we can expect a better standard of thermal control. More housing units will be air-conditioned (heated or cooled) than at present. If that is the case, the demand for electric energy resulting from the increased number of housing units will likely be compensated for by improved thermal quality (insulation) of all dwellings.

More precisely, if electricity consumption in a conventionally equipped house is on average, for captive uses, currently 2,500 to 3,000 kWh per year in France, from a purely technical standpoint that consumption could be reduced [1] to 700 kWh without diminishing the degree of comfort for users this requires technologies that we already know and will be available within a few years.

For instance, *lighting* in France accounts for almost 8 % of total electricity consumption (all sectors combined). The energy efficiency of compact fluorescent bulbs (CFB) is 4 to 5 times better than incandescent bulbs, nevertheless incandescent bulbs continue to be used in most light fixtures throughout the residential sector in Europe.

Regarding *cold production*, prospects here are also promising. Compared to the standard refrigerator that used 350 kWh per year in 1988, the best optimised version rendering the same service uses today only 90 kWh, and that consumption could drop to as little at 50 kWh per year by the 2020 deadline. A freezer that used 500 kWh every year in 1988 today uses only 180, in the

(1) Notton (G.) and Muselli (M.), « Revue de l'énergie », June 1998.

optimum version, and it is hoped that this figure will be down to as little as 100 kWh by the year 2010.

The same is true of *television sets*. The electrical power of the televisions sold in France varies from 40 to 60 W for a 36-cm colour screen and 50 to 70 W for a 55-cm screen. The generalised use of liquid crystal screens should lead to a reduction in the powers used (less than 10 W). However, the use of remote controls with the television often cause the set to be left on, resulting in considerable additional energy consumption. As *standby* consumption amounts to between 0.1 and 1.5 W, *standby* use can increase consumption by almost 50 % in some cases. Solutions for this problem are currently being studied to optimise the management of intermittent use. We hope this will provide a very significant reduction of standby consumption, and the same is true for all “brown” products.

Washing machine consumption varies hugely, depending on the wash cycle used, however, we find that the majority of the energy used (90 to 95 %) is due to heating the water. The use of microwave systems should drastically scale back consumption here. Instead of using 400 kWh a year on average, we hope consumption will be down to 240 kWh by the year 2010 as more performing machines are brought on the market, and down to less than 100 kW by 2020.

There are also some promising prospects with *electric heating,* when radiant heaters are used in conjunction with a programming system in a well-insulated space. An approximate 50 % saving would appear to be an achievable target by the year 2020.

To summarise, we recall that before 2050, we expect to see both a downward trend in the unit consumption of electrical appliances yet the same service rendered, along with a considerable improvement in the efficiency of the appliances, all of which will probably have more functions than previously.

Based on the « reasonable » assumption that all households will have a 100 % equipment rate for cold equipment (refrigerators, freezers and combined fridge-freezers), washing machines (washers, dryers and dish-washers) and micro-wave ovens, and similar living habits to now, the development of performing technologies enables forecasting for the year 2050 a drop in annual consumption:

- of 30 % for household “cold” appliances (i.e. a saving of 5.1 TWh a year compared to the current situation) ;

- of 20 % for household washing appliances (i.e. a saving of 7.7 TWh a year compared to the current situation) ;
- of 50 % for lighting generally in the residential and services sector (i.e. a saving of 10 THW a year compared to the current situation).

Those various reductions are achieved using the following technologies :

- concerning cold, the development of vacuum insulating panels for a 27 % gain, an improvement in the exchanger circuits and better performance motors ;
- concerning washing appliances, the development of recycling technologies for free heat input, better performance motors, new technologies such as the washer-drier equipped with a heat pump ;
- concerning lighting, the widespread distribution of compact fluorescent bulbs and the development of light fixtures equipped with white laser emitting diodes (LEDs) especially for traffic lights.

As regards LEDs, merely replacing the bulbs currently used in traffic lights with LEDs [1] would give an immediate 65 % reduction in traffic light consumption.

1.2. The industrial sector

According to the industrial sectory, the electricity consumption in France, 125 TWh, is basically divided at the present time between engines (69 %), manufacturing processes (electrolysis, arc furnace, etc.) (18 %) and lighting (5 %). Here again, there is a vast potential for energy savings.

Electrically operated motors represent the main contribution of electricity consumption in the industrial sector. They are used in most industries, for various uses : compression (30%), pumping (20 %), ventilation (13 %) and other uses (37 %). Several solutions can be considered to reduce the electricity consumption of the motors:

- upstream of the motor: installation of electronic speed variation systems [2] ;
- motor : improved efficiency ;

(1) LED: Laser Emitting Diode.
(2) It is estimated, for instance, that the use of speed variators on pumping and fan systems saves 25 % of electricity, for a return on investment in two years.

- downstream of the motor: a more rational use of the mechanical energy produced.

The second item (manufacturing process) calls for electrical equipment such as electrolyzer outfits, furnaces (arc, induction, resistance), etc.

Similarly, the energy content (particularly electric energy) of industrial products should be considerably reduced through the use of new technologies. Already today, we see a broad dispersal of the specific consumptions in a ratio [1] of 1 to 3 for different products, whether, for instance, in the domain of construction materials or in the agro-food industry.

These efficiency gains are, in the majority, due to improvements in the existing processes or the introduction of new process, alongside gains attributable to a new production organisation, solid gains being expected from the optimisation of industrial processes using electricity.

1.3. The tertiary (services) sector

Some major electricity uses are here the same ones as mentioned for the residential sector, such as lighting and heating. Thus, electricity consumption in the services sector in France is divided between lighting (20 TWh), heating and air-conditioning (15 TWh), cold (5 TWh), domestic hot water and cooking (10 TWh), plus other uses (40 TWh). As in the residential sector, electricity consumption in the services sector is expected to diminish for these items of consumption.

The other uses in the services sector principally concern computers or machines for communication. A reduction in consumption might be achieved for instance by reducing the consumption of the electronic components (components with even smaller engraving), through changes in the technology used for the monitors, through the management of the power supply to equipment not in use, by improving the performances of the batteries on portable machines, etc.

(1) CEREN survey.

1.4. Electricity transmission

Economic and institutional technological evolutions (the introduction of new [1] electricity generating systems) may bring in some major changes in the organisation of relations between electricity supply and demand. The main function of the transmission network would switch from a flowing function to a dispatching function between a multitude of producers/consumers using and/or supplying electricity in a variety of different ways depending on the space and on the time. The way the network is managed will thus undergo deep-seated changes, hence an increased complexity in guaranteeing the “quality” of the electricity.

This distribution network is not meshed at the moment during normal operation, but will gradually be meshed to assure the dispatching function, which at the moment is restricted solely to the very high voltage (VHV) transmission network. Reducing the average transmission/distribution distances will cut down on-line losses, currently estimated [2] at 7 % of the domestic electricity consumption.

Additionally, by 2050 the technologies, firstly those of gas insulated cables then of super conductors, are likely on the one hand to enable the transmission of high electric power over long distances while limiting on-line losses and on the other hand to make it possible to bury some very high voltage transmission lines. For technical and economic reasons underground routing is difficult to imagine at the present time.

To conclude, the introduction of all the above innovations onto the market will lead to considerable savings in the medium and long term, in the domain of specific electricity uses (50 %) and approximately 30 % of savings in the domain of electric heating uses. Moreover, a strong move towards decentralised organisation and management of the energy systems should progressively take place. Along with that trend, it is expected that the new operators, attracted by the liberalisation of the energy markets, will develop equipment for the municipalities or industry that offers a better overall efficiency, re-uses heat and electricity, as well as management systems to interconnect the different flows. All that would contribute to a lower electricity demand scenario.

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(1) Those new production systems will be presented later, in point 2.
(2) That 7 % figure (i.e. approximately 30 TWh/year) does not include the energy absorbed by the pumping.
(approx. 5 TWh/year) and electricity used by the power plants while producing electricity.

2. Electricity generating technologies

To meet the supply needed in France for electric power between now and 2050, there will be competition between many technologies, centralised or decentralised, based on fissile, fossil or renewable energy sources.

The relative share of these technologies in the future electric supply system will depend on many parameters. The main parameters are :

- the foreseeable technological progress in each of the systems making up the fleet (their performance, ease of installation, etc.) and the lifetime of the installations at different time frames ;
- the foreseeable technological progress in the electricity transmission and distribution technologies that will enable to include new production systems without decreasing the quality of supply ;
- the evolution of availability and therefore the procurement cost of the different fuels (fissile and fossil) over the period ;
- the consideration of local or global environmental constraints (local gases emissions of pollutants SO_2, NO_x, CO, etc.; greenhouse gases; miscellaneous effluent discharges; nuclear waste, etc.) ;
- the growing interest shown by the population for better environmental conditions options, with a normal trend towards seeking greater democracy in the elaboration of those choices.

We briefly summarise, below, the principal results of the studies conducted for the mission on these subjects, which have been collated in two reports attached to the report on the mission (« Technological forecast for the nuclear system », « Technological forecast for the non-nuclear systems »).

2.1. Nuclear electricity output technologies

Forecasts on technological evolutions in the various electricity output systems using nuclear fuels have been analysed in depth. That analysis covered both nuclear fuels and the processing or reprocessing of those fuels, and nuclear reactors, with the triple objective of improving the competitiveness of the system, significantly reducing the inventory of high-level long-life radwaste (in particular, minimising the production of ultimate waste or spent fuels) and controlling the quantities of plutonium in the fuel cycle and in spent fuels outside of the cycle.

This last element was a determinant factor for evaluation of the technical potential of each of the systems analysed.

Technological progress primarily concerns the nuclear reactors and the nuclear fuels, spent fuels processing and reprocessing.

Of the technological systems likely to be available at international level :

- some so-called « evolutionary » systems are developments of existing technologies (increased combustion rates, increased electricity yield) ;
- other so-called « ground-breaking or revolutionary » technologies appear as emerging technologies. Research on them having already taken place demonstrate their scientific and technical feasibility, but they are not yet at industrial development stage ;
- lastly, there are other systems, still at project stage, which will require extensive research efforts before any industrial development can even be considered.

The reactors

Some advanced reactors, offering better thermodynamic yields and higher combustion rates for nuclear fuels than those currently achieved in today's pressurised water reactors, have been proposed for many years. We have selected three of them : the EPR, based on a tested technology, and two emerging systems, the first-generation high performance reactor RHR 1 (project similar to the GT-MHR [1]) and the second one RHR 2.

EPR (European Pressurised Reactor): the feasibility study is now ready and industrial development can be envisioned shortly after completion of a first industrial prototype. This is an evolutionary reactor with a gross capacity of 1 530 MWe, capable of burning UOX or MOX fuels (up to a ceiling of 50 % for MOX, in the basic reactor design). Forecast technological progress over and above the existing PWRs include :

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(1) Framatome is taking part in an international programme to develop a failsafe 286 MWe GT-MHR reactor intended to transform military plutonium. Because of its size and economic characteristics, that system would appear to be an attractive proposition for the export market : it uses potentially advantageous technologies for the development of the reactor itself and potentially in hybrid systems. That programme, beyond the backing given to the Framatome company for the GT-MHR project, is of particular interest to the CEA.

- technical provisions to guard against the consequences of a serious accident ;
- increase in lifetime, to 60 years ;
- increased combustion rates for UOX and MOX fuels. Target is a 70 GWj/t combustion rate for UOX and MOX ;
- the possible implementation of new fuels for which studies are in progress, e.g. the advanced plutonium assembly (APA).

The building or operating costs for those reactors used in our scenarios have already been evaluated fairly accurately.

The **RHR 1** (first generation high performance reactor) is characterised by more efficient energy conversion (thermodynamic yield and high combustion rates). It could benefit from progress already taken place in the domain of gas turbines. It is a fail-saf system when it comes in sizes under 300 MWe and has the advantage of a simplified architecture (no secondary cooling circuit).

Because of those potential advantages, this type of reactor has been the topic of an international programme (GT MHR reactor) in which Framatome is a partner. The first aim of that programme is to develop RHR reactors capable of burning Russian military plutonium. A prototype of this type of reactor suitable for development for the international market [1] starting in 2015, is expected to be available in a few years' time [2].

If included in the future French reactor fleet, this type of reactor would use :

- either plutonium from reprocessed spent MOX used only once in the PWR and EPR (first generation reprocessing) ;
- or directly from 20% enriched uranium [3] if reprocessing should stop and plutonium therefore becoming unavailable.

(1) The modest size of this reactor makes it a possible candidate to meet the needs of a number of small electricity grids.

(2) Note that the GT MHR is a reactor of extremely compact design, so far the feasibility of the project is proven in theory only.

(3) At the present time, this degree of enrichment is beyond the capacity of the civil plants to produce, however it is fully possible using the ultra-centrifuging enrichment process.

The following main characteristics will be selected for those reactors : gross power 286 MWe ; 47 % yield ; lifetime of 40 years; combustion rate of 130 GWj/t for UOX and 609 GWj/t (a third of the core) for plutonium [1].

These reactors will not require a massive new research programme, only a development programme up to and including the first prototype. Once that has been done, the industrial partners in the programme will be able to evaluate exact costs for that system, including the cost of fuel manufacture.

The RHR 2 reactor (second-generation high performance reactor) should, with its neutron spectrum, be able to burn actinides including plutonium, thereby significantly reducing the quantity of ultimate waste for storage. The status of that system is very different from that of the preceding ones since, its emergence some time after 2040 will require a successful major research programme on the reactor core, the fuel and the adaptation of the boiler. There is no way at present to evaluate the possible economic competitiveness of such a system. However, we can give a rough estimate of the cost [2] of a research programme that would be likely to demonstrate the technical feasibility of the system.

Fuels and reprocessing

Several solutions have been considered in replacement of the current fuels (MOX and UOX). They involve the implementation of spent fuels reprocessing methods (based on the use of MOX and UOX in the first cycle) that are basically similar to the processes used at present, but require new capital investment. The aim of all new fuels is to recycle more efficiently the plutonium contained in the spent fuels. We will look at two of those new fuels, the APA fuel and the MOX Thorium.

Advanced Plutonium Assembly (APA) fuel

This is an advanced fuel using plutonium obtained by reprocessing MOX fuel over an inert matrix. This fuel is designed to be used in pressurised water

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(1) That is the combustion rate for military plutonium composed of 95 % Pu 239.
(2) The CEA estimates the cost of research relating to the building of an experimental second-generation high performance reactor (RHR 2) over the period 2010-2020 at 200 million FF per annum between 2000-2010 and 700 million FF per annum between 2010 and 2050. Those costs include R&D on the reactor and on the fuel cycle, plus the building of an experimental reactor over the period 2010-2020.

reactors. Its potential advantage resides in that it will be able to recycle the plutonium several times, which should enable better control of the stock of plutonium. No demonstration of this fuel has been made, yet. The technical and industrial feasibility therefore depends on an ambitious research programme under way at the CEA and the need for demonstration of the technical and economic advantages of advanced multiple recycling. If such a programme [1] is successful, this fuel could be in use in PWR reactors by 2020. This would signal the start of a significant reduction in the stock of unusable plutonium over the period 2030 to 2050.

MOX Th

This alternative solution to APA fuel consists of recycling the plutonium from spent MOX to obtain a fuel based on plutonium oxide over a matrix of thorium oxide. That fuel, contrary to APA, will not be appropriate for multiple recycling and will therefore require ultimate disposal.

According to the quantities of high-level long-life radioactive products remaining at the end of the cycle, the performances of these various potential technologies yield highly diverse results, as shown in the table below.

Material balance, calculated per TWh of electricity generated using the different technologies proposed, in kg/TWh

Reactor type	**EPR**	**EPR**	**EPR**	**EPR**	**RHR1**	**RHR2**	**RHR1**
Fuel	**UOX**	**MOX**	**APA**	**MOX Th**	**Pu**	**Pu**	**U**
Yield	0.36	0.36	0.36	0.36	0.47	0.50	0.47
Combustion rate (GWj/t)	64	55	89	60	610	480	130
Plutonium	***22***	***- 53***	***- 69***	***- 108***	***- 112***	***- 62***	***15***
Minor actinides	***4***	***19***	***16***	***7***	***12***	***-13***	***2***
Fission products	***117***	***119***	***119***	***117***	***90***	***84***	***90***

N.B. : Only approximately 8 to 12 % of those fission products, depending on the systems, consist of high level long-life products

(1) From the industrial standpoint, we recall that by 2020 the existing reactor fleet will have reached an average age of 35 years and that the prime concern for the operator at that time will be to extend the lifetime of its power plants.

Whereas the EPR technology using UOX produces plutonium, all the three technologies using MOX, APA or MOX Th fuels consume plutonium (to different extents). The RHR technologies also consume plutonium.

Concerning minor actinides, only the RHR2 technology yields significantly different results from the others, since it consumes minor actinides whereas all of the others actually produce them (production of 2 to 20 kg per TWh depending on the technologies).

Lastly, the RHR technologies, which give a better yield than the EPR, produce 23 to 29 % less fission products.

The nuclear systems [1] chosen in the different scenarios call in varying degrees for the different technologies described above. The criteria used to guide the choice between systems depend both on the volume of nuclear capacities to be built in each of the scenarios and on the constraints imposed by the general policy guidelines underpinning each of the scenarios.

2.2. Technologies for electricity production using fossil and renewable energy sources

Forecasts for the technological evolution of the various electricity production systems using fossil and renewable energy fuels were analysed in depth (see the group's final report « Technological forecasts for non-nuclear systems »).

That forecast analysis was conducted on both centralized and decentralized [2] means of power generation based on a "critical" inventory of the technologies and an assessment of the economic forecasts [3] for the different systems at different time frames. The chosen yields selected over the period from now until 2050 were based on the net calorific values. In our approach we also looked at the positioning of the technologies in the demand curve used as a reference, and

(1) By « system » here, we refer to a fleet comprising several different reactor types and different fuel types.

(2) By definition, we refer here to « decentralized or dispersed electricity» when it does not transit via the 400 kV or 225 kV transmission network.

(3) We did not consider the technologies for the capture of CO_2. Note merely that the use of such technologies would reduce the indicated yields by approximately 20 % for the centralized gas-fired means of production, and by a great deal more for decentralized production by a conventional thermal power plant.

the forecast study of electricity transmission infrastructures and the necessary gas transportation/storage and costs involved.

The various power generation technologies we studied were shared between centralized and decentralized production.

Centralised production

Combined Cycle using Natural Gas (CCNG),
Gas Turbine (TAG GN) and Advanced Gas Turbine,
Fuel Turbine using domestic fuel oil (TAC FOD),
Integrated Gasification Combined Cycle (IGCC), using coal or petroleum waste,
Circulating fluidised bed (LFC), carbon [1].

Decentralized production

Gas engine in co-generation
Combustion turbine in co-generation
Small and micro turbine in co-generation
Stirling engine in co-generation
Fuel cell
Wind generator (offshore and onshore wind farms)
Steam Turbine.

Hydro or micro-hydro technologies were not studied here since this technology has almost reached saturation point in France and therefore has little potential for future development. However, the information used to assess the potential assets of solar energy (photovoltaic electricity and solar heat production) is presented in the specific report on dispersed electricity production. For each of the technologies, the forecast analysis led us to envision a significant evolution of the main parameters characterising their performances. The efficiency [2] of

(1) The coal-fired technologies described in the group's report are not mentioned in this chapter inasmuch as the various scenarios described later do not use coal-fired facilities after the year 2020, even if coal is likely to appear to be a potential fuel in technologies using natural gas.
(2) Two definitions are used to characterise the efficiency of a conventional thermal power plant due to the fact that during combustion which produces $C0_2$ and water, some of the emitted heat is absorbed by the water. A fossil fuel is therefore characterised by two calorific values, the gross calorific value (PCS) – the maximum

the installation in particular appears to be the main factor, since it is the improvement in efficiency that enables a) reducing the consumption of fossil fuels and b) reducing emissions of CO_2, the worst offender in terms of greenhouse gas.

2.2.1. Centralized production

Natural Gas Combined Cycles (NGCC) 600 to 800 MWe

The natural gas combined cycle consists of a gas turbine (TAG) alongside a steam turbine (TAV): the hot gases from the gas turbine are used to prepare high-pressure steam for injection into the steam turbine.

In most of the scenarios [1] considered, but particularly in scenarios H1 and B4 which do not suppose a renewing of the current fleet of reactors with new nuclear plants, the role of high power NGCC is prominent in assuring base or semi-base load electricity needs. That technology, in a context of a liberalised electricity market and low natural gas prices, currently enjoys strong industrial and commercial development in countries across the world. The system benefits from lower greenhouse gas emissions than the ones of coal and fuel-fired technologies, considerably shorter building times and lower investment costs than for nuclear or coal-fired power plants (at approximately 3,000 FF per kWe). However, the cost of the electricity produced depends greatly on the cost of gas (60 to 70 % of the cost).

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quantity of heat emitted by a unit of mass – and the net calorific value (PCI) – the maximum quantity of heat emitted by a unit of mass minus the losses due to the water. The difference PCS-PCI is 5 % for oil fuels and 10 % for gas fuels.

(1) Those scenarios are presented in chapter 4.

Forecasts for the evolution of the characteristic parameters [1] of that technology are presented in the table below :

NGCC 600–800 MWe	**2010**	**2020**	**2030**	**2040**	**2050**
Efficiency (net calorific value)	56 %	60 %	60 %	65 %	65 %
Lifetime	25 yrs	40 yrs	40 yrs	40 yrs	40 yrs
Emissions of C g/kWh*	100	90	90	85	85

* *excluding emissions from the natural gas supply chain overall*

The efficiency of those turbines could increase from 55 % reached today to 65 % at the end of the study period, and their lifetime will be extended from 25 to 40 years.

Natural gas combustion turbines [2] (TAG GN) 250 MWe

These gas turbines with a lower capacity are the main component of the NGCC, but can also supply the peak-load demand for power (< 2,000 hours per annum). Because of their moderate investment cost (around 2,000 to 2,500 FF per kWe) they are competitive for peak-load applications. Forecasts for the evolution of the parameters characteristic of that technology are presented in the table below :

TAC 250 MWe	**2010**	**2020**	**2030**	**2040**	**2050**
Efficiency (net calorific value)	40 %	40 %	45 %	45 %	50 %
Lifetime [3]	25 yrs	30 yrs	30 yrs	40 yrs	40 yrs
Emissions of C g/kWh*	135	135	120	120	110

* *excluding emissions from the natural gas supply chain overall*

With the improved efficiency obtained by introducing different technological alternatives to the initial concept (such as injection of water into the turbine, for instance) we can envision the potential use of these turbines for up to 3,500

(1) In the calculation of the carbon emissions, we did not specify the calorific value of the gas used : currently, the gas imported into France has an average calorific value of 38 MJ/m^3 (ranging from 33 MJ/m^3 for Dutch gas to 42 MJ/m^3 for Algerian gas).
(2) These turbines are mainly used in a combined cycle with natural gas. The isolated use of those turbines is reserved to meet peak-load demand.
(3) Some experts envision a lifetime of 35 years by 2020 both for gas turbines and for turbines using domestic fuel oil.

hours a year in competitive conditions. This would effectively fill in a gap between the power plants used to supply the base-load demand, and the simple combustion turbines.

Diesel (fuel oil) turbines (TAC FOD) 150 MWe

These turbines run on fuel oil (domestic fuel), a fuel that is easier and therefore less costly to store than natural gas. They are aimed at filling peak-load electricity demand (< 1,000 hours a year). The technologies have now arrived at maturity [1] and are consequently not expected to evolve very much. The option of using these turbines rather than natural gas turbines is justified for short-term use because of the expenses involved in building gas pipelines and storage facilities. The main characteristics of these turbines are indicated below:

Fuel-oil Turbines TAC FOD 150 MWe	**2010**	**2020**	**2030**	**2040**	**2050**
Efficiency (net calorific value)	40 %	40 %	40 %	40 %	40 %
Lifetime	25 yrs	30 yrs	30 yrs	40 yrs	40 yrs
Emissions of C g/kWh*	190	190	190	190	190

* *excluding emissions from the diesel fuel supply chain, including refining process*

2.2.2. Decentralized production

Internal combustion engines in co-generation

These engines are used for the combined generation of electricity and heat with capacities [2] ranging from 5 kWe to 5 MWe when operating on natural gas. The first application for electricity production was driven by economic considerations. Later, these engines were used as standby generators when they used a fuel which can be stored (such as domestic fuel oil). In recent years, this technique has been specifically orientaded towards electricity production in co-generation. In the current fleet of co-generation installations, the combustion engine represents 53 % of the machines used [3]. Despite the large fleet, this

(1) This caused us to opt for a lesser improvement in the yields between now and 2050 than the yield chosen for fuel turbines using natural gas.
(2) The average capacity of an installation in France amounts to 2.5 MWe.
(3) CEREN survey performed for the secretariat of state for Industry « French co-generation facilities on 31.12.1997 »

technique represents only 14 % of the installed capacity for co-generation in France.

Its electric efficiency is relatively high (37 % on average) and continues to improve : installations are on the market at present with efficiencies of over 42 %. The high availability rate (95 %) and speed of implementation make this technique a very suitable solution (for combined electric energy and heat production) for the multiple needs of some industrial or tertiary sectors.

Combustion engines in co-generation	**2 000**	**2 010**	**2 020**	**2 030**	**2 040**	**2 050**
Energy efficiency (net calorific value)	39.5 %	42 %	45 %	48 %	50 %	50 %
Lifetime	15 yrs	15 yrs	20 yrs	20 yrs	25 yrs	25 yrs
Emissions ** of C g/kWh*	140	130	120	115	110	110

* *excluding emissions from the natural gas or fuel oil supply chain*

** *of which a variable proportion of between 30 % and 50 %, attributable to the thermal application of co-generation depending on the evolutions of the electricity production and thermal production respectively*

Combustion turbines in co-generation

In a cogeneration system, the turbine generates electricity, and the combustion gases supply a boiler. In France, 90 % of combustion turbines use natural gas, the remainder use other gases, domestic fuel oil or heavy fuel.

The unit capacity of these turbines is between 5 and 10 MWe. The energy efficiency was 24 % on average, in 1994, and reached 31 % by the end of 1997. The improvement in the recovery cycle (exchanger between the air leaving the compressor and smoke leaving the turbine) and the use of materials resistant to high temperatures make it possible to achieve energy efficiencies of approximately 45 % [1] for a comparable cost. The advantage of the « co-generation » concept basically resides in the extent of overall energy efficiency (electricity plus heat), which makes co-generation seem the most economic methods of production in terms of cost per kWh.

(1) At the 2020 time frame, some international R&D programmes on energy technologies use efficiencies of 52 % for a simple cycle, with 25 % reduction in the production cost, however, we have not use in our study such optimistic figures.

By optimising the combustion process, a 50 to 70 % reduction in NOX emissions can be achieved (depending on the power of the turbine) and an even bigger reduction in CO_2 emissions.

Combustion turbines account for two-thirds of the new installed power.

Combustion turbine in co-generation	**2 000**	**2 010**	**2 020**	**2 030**	**2 040**	**2 050**
Energy efficiency (net calorific value)	33 % [1]	40 %	40 %	45 %	45 %	50 %
Lifetime	25 yrs	25 yrs	25 yrs	25 yrs	25 yrs	25 yrs
Emissions ** of C g/kWh*	165	140	140	120	120	110

* *excluding emissions from the entire natural gas supply chain*

** *of which a variable 30% to 50% proportion can be attributed to the thermal application of co-generation, depending on the evolution of thermal and electric efficiencies*

Small and micro turbines in co-generation

Leading manufacturers have invested in the bottom end of the mini co-generation market in Europe, which numbers more than ten thousand installations [2] : the Netherlands has 2,500 installations (average power of 125 kWe) compared to approximately 30 in France.

Those installations are marketed in the form of ready-to-use modules equipped with three inputs (gas, combustion air, water to be heated) and three outputs (smoke, heat, electricity). The modules are fairly small sized (approximately that of a standalone boiler on feet for a 5.5 kWe and 12.5 kWth module).

The mini co-generation market is virtually entirely occupied at present by gas-fired engines. However, the needs for on-board or mobile energy applications have spurred research in the domain of micro-turbines. Over the past five years, the supply has emerged for the industrial, tertiary and residential sectors of very small turbines with a power between 5 to 250 kWe. These small turbines accept all types of fuel (waste gas, gas of the network, gas from methanisation, LPG, natural gas). Like the large sized turbines, optimisation of the combustion

(1) Some manufacturers already have projects with 40 % efficiency, and the average yield is apparently almost 35 % already.
(2) « Énergie Plus » review n° 237, December 1999.

process will noticeably reduce NOX emissions. The reduction of CO_2 emissions is directly dependent on improvement of the overall performance of the installation, particularly as a result of the heat recovery systems. Currently, the turbines have an approximate 30 % energy efficiency, the manufacturers' announced objective being to reach the level of performance achieved in large-scale installations (energy efficiency of 40 %).

Some manufacturers announce for the medium term prices of around 350 to 550 dollars per kWe [1], which would make this technology a competitive's one.

Small and micro turbine in co-generation	**2 000**	**2 010**	**2 020**	**2 030**	**2 040**	**2 050**
Energy efficiency [2] (net calorific value)	30 %	35 %	37 %	40 %	40 %	40 %
Lifetime	15 yrs	15 yrs	20 yrs	20 yrs	25 yrs	25 yrs
Emissions ** of C g/kWh*	180	155	145	140	140	140

* *excluding emissions from the fuel supply chain*
** *up to 50 % of which is attributable to the thermal applications of co-generation*

Stirling engines in co-generation

The Stirling engine is an external combustion engine. External combustion enables a reduction in pollutant emissions and a simpler maintenance. It allows the use of a large spectrum of fuels and heat sources (solar energy [3], conventional fuels, biomass, waste). Moreover, the Stirling engine is also very silent. The design of this engine means that very small capacities can be installed (approximately 1 kWe). The pre-commercial range available has a capacity of between 5 and 50 kWe (for a thermal efficiency of approximately twice that figure).

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(1) EGSA Review « Powerline », November-December 1998 (www.egsa.org).
(2) According to EDF, the yield at the moment would be closer to 25 % and 30 % would be a realistic target, even if an efficiency of 42 % has already been attained on a Japanese prototype.
(3) Mentioned in « REE » n° 7, the US DOE's research programme on « solar dish-Stirling » engine with energy efficiencies of close to 30 % as against 10 to 15 % for the photovoltaic system.

Five industrial companies are currently involved in developing and marketing Stirling engines and other companies have partnered their progress. The threshold aimed at, from the economic standpoint, is approximately 5,000 FF per kWe compared to almost twice that at the current time. According to British Gas, batch production scheduled to start by 2002 should bring these engines down to a marketable price. The reference niche market for the Stirling engine is the on-site production of low voltage electricity (220 V, 50 Hz) and low temperature heat, which might be of prime interest in the residential sector. As a reminder, the large number of isolated houses in France (12 million) with an average unit consumption of specific electricity (2,500 to 3,000 kWh per year) gives an idea of the stake that these engines represent (8 % of the domestic electricity consumption). The pre-commercial range currently under preparation is aimed at a capacity of 0.35 to 30 kWe.

Stirling engine	**2 000**	**2 010**	**2 020**	**2 030**	**2 040**	**2 050**
Energy efficiency (net calorific value)	25 %	30 %	33 %	35 %	40 %	40 %
Lifetime	15 yrs	15 yrs	15 yrs	15 yrs	15 yrs	15 yrs
Emissions ** of C g/kWh*	220	180	165	155	140	140

* *excluding emissions of the fuel supply chain*

** *up to 50 % of which is attributable to the thermal applications of co-generation*

Fuel cells

The fuel cell is based on the reverse principle of water electrolysis and thus allow the saving of converting thermal energy into mechanical energy. It is a technological breakthrough compared to the general schemes for electricity production and in theory achieves high-energy efficiency. The first industrial developments, achieved as the result of American research and the space programmes [1] have enabled developing tangible applications based on those concepts.

Even before the first oil crisis in 1973, international research was already interested in this field, hoping to see one or more systems emerge out of it that would make highly efficient use of various fossil fuels or biological energy sources.

(1) Gemini, Spacelab, Apollo, etc have used fuel cells.

Currently, efforts are being made first of all to make intelligent use of the particular qualities of this method of production by using it at scales or in concepts where concurrent engineering methods pose environmental problems.

The energy efficiency, which can be as high as 40 to 60 %, is not limited by the Carnot principle and depends very little on change of scale: a 100 We cell has an energy efficiency comparable to a 1 MWe system [1]. The resulting modularity allows considering application for various types of use in the transportation, industrial, tertiary and residential sectors and even, very recently, in portable equipment. Furthermore, its almost negligible impact on the local environment (local noise emission and atmospheric emissions) means that fuel cells meet very stringent emission standards (at least one order of magnitude less than concurrent systems for NOX, for instance).

We should also point out the specific possibilities allowed by the high temperature systems: they can achieve an energy efficiency of 60 % to 70 % in a hybrid cycle (cell coupled with a gas turbine). Fuel cells can use either hydrogen or carbon fuels such as methanol or methane as the fuel, subject to an in situ *reforming* operation. Being able to use the hydrogen produced by the petroleum products [2] would enable CO_2 emissions to be centralised, which is the only solution compatible with a possible future sequestration of the CO_2.

Costs at present are very high, around 20,000 FF/kWe at best, or even more, depending on the systems. The R&D work in progress is aimed at reducing the costs by a factor of ≥ 10 or more for stationary or heavy traction uses, or perhaps by a factor of ≥ 100, a necessary condition if the fuel cell is to be competitive for use in cars.

The following tables are based on the assumption that the fuel cells are using methane as the fuel.

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(1)Bezian (J.-J.), « Systèmes de piles à combustible pour la cogénération - État de l'art », (Fuel cell systems for co-generation – State of the art) the Energy Centre of the Ecole des Mines, Paris, ADEME, 1998.

(2) In the longer term, we can envision producing hydrogen without either the direct or indirect use of fossil fuels, either by electrolysing the water with electricity from a non-fossil source, or by cracking the water in high temperature nuclear reactors.

PAC 30-70 kWe unitary-car Low temperature	2010	2020	2030	2040	2050
Efficiency (PCI **) of the fuel	43 %	50 %	53 %	58 %	60 %
Lifetime	15 yrs 3 000 hrs	15 yrs 5 000 hrs	15 yrs 6 000 hrs	20 yrs 6 000 hrs	20 yrs 6 000 hrs
Emissions of C g/kWh *	130	110	105	95	90

* *excluding emissions from the natural gas supply chain*

PAC 500-2000 kWe unitary High Temperature	2010	2020	2030	2040	2050
Efficiency (in hybrid cycle) /PCI ** natural gas	58 %	63 %	66 %	70 %	72 %
Lifetime	15 yrs	15 yrs	18 yrs	20 yrs	25 yrs
Emissions of C g/kWh *	95	85	80	75	75

* *excluding emissions from the natural gas supply chain*

** *PCI lower calorific power*

Wind generators

The wind generator design is based on the principle of transforming the kinetic energy of wind into mechanical or electrical energy. The generator is composed of a rotor, an electrical transmission and a generator which transform the mechanical energy into electricity. The ability to generate electricity depends on the availability of a wind resource of sufficient velocity. For instance, for a wind generator of nominal capacity 300 kWe, the effective power is 4 kWe for a wind speed of 5m/sec, 122 kWe for a wind speed of 9m/sec and a nominal power is achieved at 14 m/sec. The profitability of the project is therefore tied directly to the availability and average velocity of the wind resource. The availability of the wind resource determines the siting of the project.

In terms of offshore potential, France ranks n° 3 in Europe as regards wind resources, behind the United Kingdom and Denmark, with a potential [1] of 475 TWh annually. In terms of onshore potential, the European Association for Wind Energy estimates resources at approximately 75 TWh/year, with France

(1) « Offshore Wind in the EC » Study, Matthies (H.G.) et al., 1995.

ranking top in Europe. However, wind resources are generally far removed from populated areas, as people rarely choose to live in windy areas.

In this type of project, savings are achieved basically as a result of the low cost of connection to the transmission or distribution network. The potential [1] that can be called in France would be approximately 10 % of the wind resource, i.e. 50 TWh /year.

At a cost of around 10 000 F per kWe for an offshore installation, onshore wind generators usually work out 10 to 35 % cheaper. The principal foreseeable technical improvements concern optimisation of the blades and the generator, and should shortly result in better performances for these installations, expressed as an improvement in the capacity factor (in number of hours per year at nominal power).

Offshore wind generator 1-3 MWe	**2000**	**2010**	**2020**	**2030**	**2040**	**2050**
Capacity factor (hours/year)	3 000	3 100	3 200	3 350	3 450	3 550
Lifetime	15 yrs	15 yrs	15 yrs	15 yrs	20 yrs	20 yrs
Emissions of C g/kWh	0	0	0	0	0	0

Onshore wind generator 0.2-0.75 MWe	**2000**	**2010**	**2020**	**2030**	**2040**	**2050**
Capacity factor (hours/year)	2 600	2 700	2 800	2 900	3 000	3 100
Lifetime	15 yrs	15 yrs	15 yrs	15 yrs	20 yrs	20 yrs
Emissions of C g/kWh	0	0	0	0	0	0

(1) According to a report from EED (a French research department specialised in wind generators).

Chapter 4

Prospective scenarios for France

1. Two demand scenarios [1] up until the year 2050

1.1. Energy demand

According to the orientations [2] stipulated for this mission, we have limited the spectrum of possible trends in the demand for energy to two highly contrasted pictures in 2020 and 2050.

The 2020 deadline corresponds to scenarios S2 and S3 of the « Energy 2010-2020 » report. Those scenarios explore two different socio-political contexts with a single set of hypotheses for economic growth, population growth and international energy prices.

Scenario S2 of the « Energy 2010-2020 » report describes an evolution in which the State once again becomes interventionist in the economic and industrial domain, with the aim of identifying the long-term interests of the nation with the strength and competitiveness of its industry. In S2, the design and implementation of the different public policies that have implications in the domain of energy, for instance, the environmental policies, are systematically understood as having the objective of encouraging the competitiveness and expansion of the French industry, while remaining compatible with European regulations and those of the Organisation of World Trade (OWT).

In scenario S3 of the « Energy 2010-2020 » report, the State promotes first of all some values such as the protection of the health of the population, the

(1) The scenarios presented in chapters 4 and 5 were defined by the mission and modelled by the Enerdata company under the scientific responsibility of B. Chateau.
(2) « …this study will take into account the different hypothesies contained in the report prepared by the French Planning Office « Energy 2010-2020 » and the international context on energy… ».

prevention of technological risks and preservation of the environment on the local and on the global scale. The State leaves to the corporate interests, professional associations and social partners the work of piloting the economic changes, on condition, always, that they remain compatible with the objectives and the framework fixed by the State.

This led us to select two scenarios for the 2050 deadline, which, though contrasted, comprise some common variables such as the demography and economic growth.

Demography and employment

The future demographic movements in France converge upon an ageing population. The chosen demographic scenario reflects a continuing trend [1] already observed over the past 20 years in terms of mortality, fecundity and migration. It is based on a set of three hypotheses : a continuing drop in the mortality rate ; a net average annual migratory flow of 50,000 peoples ; a fecundity rate of 1.8 child per female [2].

According to these hypotheses, the population [3] of France would increase from 58.5 millions [4] in 1999 to 65.1 millions in 2050 (63.5 in 2020).

Economic growth and production

Demographic constraints will progressively impact the growth of GDP, more or less strongly depending on productivity gains at work. From now until 2020, we use the same hypothesis for the growth of GDP as used in the « Energy 2010-2020 » report, i.e. an average of 2.3 % per annum. After that date, we presume that the growth rate dips progressively to reach an average level of 1.6 % per

(1) It corresponds to the « central » scenario selected by the INSEE based on forward planning determined on the basis of the 1990 survey. Q.-C. Dinh : « The population of France in 2050 », « Économie & Statistique », n° 274, 1994-4.
(2) This is an intermediate hypothesis between a low-fecundity hypothesis (1.5 child for every woman) and a hypothesis which enables renewal of the generations (2.1 children for every woman). The evolution of fecundity observed since the date of the forecast conforms to this hypothesis.
(3) We refer here to all the population habitually resident in metropolitan France : that includes foreigners who have settled to work, study or reside permanently in the country. It does not, however, include French people living in the French overseas territories, or abroad.
(4) According to the 1999 population census, « INSEE-Première » n° 691, January 2000.

annum over the period 2020 to 2050, the growth rate used by the International Institute for Applied Systems Analysis (IIASA) for the European region between 2010 and 2050.

On these common bases, we have selected two contrasting scenarios for energy demand :

- a **high-demand** scenario reflecting « *high energy consumption* », in which the 2020 stage is the one of the scenario S2 of the « Energy 2010-2020 » report and in which the 2050 stage is the translation for France of the image of Europe as described in scenario A of the IIASA analysis, characterised by high energy demand. Although this scenario accords no particular importance to environmental issues, it nevertheless includes what are considered realistic hypotheses on the constraints arising out of the impact of environmental concerns in the future, whatever the other circumstances may be, and the technical orientations arising out of those concerns (such as voluntary agreements by industry, and in automobile manufacture, standards of insulation, etc.). In such a scenario, the demand for energy (that is, primary energy excluding non-energy uses) could be as high as approximately 325 Mtoe in 2050 (210 in 1998). This corresponds to approximately 5 toe/inhabitant in 2050, a unit consumption that can be compared to the figure of 3.5 reached in 1998 ;

- a **low-demand** scenario reflecting « *low energy consumption* » in which the 2020 stage is the one of the scenario S3 of the « Energy 2010-2020 » report and in which the 2050 stage is the translation for France of the image of Europe described in scenario C of the IIASA. In this scenario, environmental constraints become determinant and therefore promote all those orientations that result in a stabilisation followed by a reduction in emissions and the production of undesirable wastes. The energy demand in this scenario would be approximately 225 Mtoe in 2050.

High (H) and Low (B) energy consumption scenarios

			H		B2, B3		B4	
	1998		2050		2050		2050	
	Mtoe	**%**	**Mtoe**	**%**	**Mtoe**	**%**	**Mtoe**	**%**
Residential	62	30	100	30	75	33	75	33
Incl. Heating	36		45		35		35	
Production sector	96	46	140	43	90	39	90	39
Inc. LV-MV *	27		30		20		20	
Transport	52	24	90	27	65	28	65	28
Sub-total	210	100	330	100	230	100	230	100
Deductible heat **			5		5		8	
Total	210		325		225		222	

* *low and medium temperature heat*

** *the deductible heat is the one produced at the same time as electricity in co-generation and which is therefore deducted from the overall heat needs*

The factors of uncertainty that may explain the noteworthy differences between differential energy consumption forecasts for the 2050 time frame (a 44 % gap between high-demand and low-demand scenarios) include :

- *economic factors* such as a slower growth of the economy than anticipated, since the growth rate has a major influence on the impact of energy on GDP ;

- *factors relating to land development and transportation infrastructure options*. The dual trend that has been observed continuously over the past 70 years, is expected to continue, though with gradually diminishing effect ; the first trend is for increasingly dense development of the rural areas around urban centres exceeding a given size to the detriment of remoted rural areas ; the second for a gradual movement of the population away from urban centres generally.

Although unfavourable for mass transportation within urban zones, this dual trend however creates more favourable conditions for mass transportation between urban zones.

Alongside such changes, we anticipate that mobility aspirations will remain high and, just as in the past half-century, those aspirations will be generally met only by increasing the average speeds of travel.

We can therefore anticipate that research on increasing the average speed of travel will continue. However, the same overall result could be obtained in a more or less egalitarian manner with heavy implications for the demand for power (and electricity) : due either to the development of infrastructures adapted to limited traffic travelling at very high speeds (aircraft, high speed train (TGV), or to the development of infrastructures adapted to much heavier traffic travelling at lower average speeds (overhead trains, etc.).

The table below illustrates these above comments by showing the impact of those different hypothesis on the volume of traffic chosen in the scenarios for the different modes of railway transportation in 2050.

	1997	**2020**	**2050**
Railways - passenger traffic trend (billions of passengers per km)	72	104 - 119	150 - 250
Railways - goods traffic trend (billions of tonnes per km)	42	62 - 79	100 - 160
High speed train TGV (index)	100	190 - 280	300 - 500

- *technological factors*

In the technological domain, two opposing trends can be seen :

- a more or less pronounced trend towards improving the energy efficiency of all equipment designed to meet service requirements (domestic comfort, travel, industrial and agricultural production, etc.) ;
- an industrial and commercial drive to create new services and equipment for the market.

That balance is likely to be extremely sensitive to incentive policies practised by the public authorities. Restraining the energy consumption through tax policies or regulating the secondary component and simultaneously promoting the supply of performing technologies will achieve distinctly lower consumption levels than would be achieved with the opposite policy.

The principal technologies for energy control

In the domain of energy control, technical progress rests on the parallel evolution of a large number of technologies in the fields of materials, electronics, control, information, architecture, process engineering, catalytic chemistry, etc. It is difficult to list them all, yet we can nevertheless give a few examples in different fields.

Industry

High-energy-consumption industrial processes call for generic techniques such as fusion, separation, concentration and drying, for instance : techniques that generally use thermal energy. For purposes of separation, membrane processes (especially the emerging nanofiltration process) ; for concentration purposes, mechanical steam compression (MSC) ; for distillation, pervaporation at ambient temperature and for energy transfers (in drying or fusion for instance) energy recycling and the development of radiant energies (ultraviolet, infrared, high frequencies or microwaves) are technologies where progress is likely in terms of increased efficiency. The potential medium-term savings in the energy demand across all of those processes could possibly exceed 30 %.

The development of new materials (ceramics, biomaterials, superconductors), new processes or systems associating new combinations of techniques (hydrogen reduction in the iron and steel industry, dry processes in paper mills, etc.) will also result in considerable energy savings (20 % or 30 % or more within the next 10 or 20 years).

Residential tertiary sector

Concerning heat and cold production, much progress can still be achieved in the design and optimisation of the building shell : variable glazing properties (potential energy savings on the overall balance of heating, air-conditioning and lighting needs amounting to 20 to 50 %), high performance insulants (for instance based on silica aerogels) potentially enable a gain by a factor of 1.5 to 2 over the insulation performances of non-transparent windows. Concerning heat production, the small co-generating machines allow a potential gain of approximately 60 % over the production of heat and electricity (fuel cells, microturbines) ; performing ventilation systems for new construction and renovation work (control, programming, recycling of heat from the extraction air) ; energy control technologies that achieve considerable potential gains.

Transportation

In this domain, the energy efficiency of road vehicles (private vehicles and trucks) is the number one priority.

Several technologies are currently in the research and development phase and should be in widespread use over the forthcoming 5 to 15 years : hybrid vehicles, fuel cell vehicles and electric vehicles. A gain in energy efficiency of between 30 to 40 % is anticipated. Moreover, more lightweight vehicles and research to find more aerodynamic designs should enable additional efficiency gains of around 10 %.

- *Environmental factors*

The intensity of local or global environmental concerns (whether as regards pollutants or local effluents, the greenhouse effect, nuclear waste, etc.) in France and throughout the world in the years to come will no doubt strongly influence the consumption of energy and therefore electricity. In particular, the way these concerns are translated in terms of prices or costs will impact the evolution of energy demand. For the greenhouse effect, for instance, the availability of unlimited flexibility in the instruments would have radically different consequences on the country's energy consumption compared to a stringent national quota system.

1.2. Electricity demand

Two scenarios for ***electricity consumption*** are associated with these energy scenarios, based on a differential evolution of the penetration of electricity into the different sectors of economic and social activity.

First of all, a fact : in 1998, the share of electricity in the French primary power balance amounted to 39 % [1] compared to an average of just 32 % in Europe ; in 2020, in the « Energy 2010-2020 » report, France continues to enjoy a penetration rate for electricity that is 5 points higher than the one of its European neighbours, however that rate remains fairly constant : the share of electricity in the French primary energy balance amounts to 40 % in the high-demand scenario and 42 % in the low-demand scenario.

For the period after 2020 we assume a continuing penetration for electricity and a gradual levelling out of the situation in Europe over the long-term. This would still lead France towards a high penetration rate for electricity, yet one that at approximately 50 % would be comparable with that of its neighbours in 2050.

(1) Adopting the production equivalence of « 1 TWh electricity = 0.22 Mtoe » used in the energy balances of the DGEMP (French General Directorate for Energy and Raw Materials).

The gradual rise of electricity in the overall energy balance has been observed historically over a long period of time and can be explained by the transformation in the structure of the use of electricity, which is increasingly used in tertiary activities, high-tech industries and the residential sector. More precisely :

- In the ***high-demand scenario***, electricity, at 720 TWh represents a little under 50 % of the total consumption of primary energy.

In terms of demand for electricity, that scenario is generally characterised by :

- a strong predominance of mains electricity encouraged by lively competition among grid industries and relatively low electricity prices ;
- fairly high intensity of electricity production ;
- an increasing number of appliances and equipment in the houses, with consumption modes patterned on the American lifestyle ;
- continuing high penetration rate for electricity in heating, hot water and cooking uses, in new housing.

We can summarise the main characteristics of this scenario by the following indicators.

Indicators selected for the high demand/low demand electricity scenarios

		High demand scenario		Low demand scenario	
	1997	2020	2050	2020	2050
Production					
- Trend * for intensity of electricity production	100	83	65	77	55
- Intensity of use (use/m2)	100	87,5	75	112,5	125
- Efficiency gains compared to trend *		0 %	0 %	9 %	20 %
- Own production, co-generation, fuel cell		11 %	11 %	11 %	35 %
Lifestyles, housing					
- Specific uses of electricity (trend * kWh/dwelling)	2 460	3 200	4 300	2 300	3 600
- Electric heating in new housing		50 %	50 %	50 %	20 %
- Sanitary hot water, electric cooking (% dwellings.)		45 %	45 %	45 %	40 %
- Fuel cells		0 %	0 %	0 %	30 %
- Efficiency gains compared to trend *					
Specific use		0 %	0 %	9 %	20 %
Heating		0 %	0 %	10 %	15 %
Transportation					
- Passengers-km railway	72	104	150	119	250
incl. High speed train (TGV)	27	76	135	51	81
- Tonnes-km railway	42	62	100	79	150

* *The term « trend » is understood to mean an overall evolution consistent with the spirit of the scenario, without any specific, direct intervention by institutions in the domain of energy control that would be likely to produce additional gains in terms of energy efficiency*

- In the ***low-demand scenario***, electricity at the level of 535 TWh in 2050 would represent a little over 50 % of the total consumption. That slightly higher penetration rate chosen for electricity in the low-demand scenario is due to the hypothesis of an increase in the development of railway transport on the one hand, and potentially lower gains in energy efficiency for electric uses than thermal uses and road transport.

In terms of electricity demand, that scenario is generally characterised by :

- a less predominant position of electricity delivered through the main network offset by a strong development of own-production techniques (50 TWh in 2050), made possible in part by the increased price of electricity delivered through the main network and in part by better technological and industrial control of the individual technologies ;
- less economic intensity of electricity production alongside a deep-seated transformation in the organisation of the work ;
- an increasing awareness in households of the « environmental friendliness » of the household appliances and modes of consumption ;
- a weaker growth of the high speed train (TGV) yet a greater expansion of the other railway networks and associated services ;
- the marketing of goods and services aimed at improving electric efficiency.

The differential evolution in electricity demand between high- and low-demand scenarios is summarised in the table below. In 2050, electricity demand in the high-demand scenario is only 35 % higher than in the low-demand scenario (whereas energy consumption amounts to 44 %), particularly as a result of increased electricity consumption in the transport sector, in the low-demand scenario :

Final consumption (1) TWh	1997	2020 (2)		2050	
		S2	S3	High demand	Low demand
Productive sectors	228	302	269	400	275
Transport	10	20	23	40	55
Household	126	162	142	280	205
- specific	59	76	62	135	90
- heating	44	58	52	75	55
- others	23	29	28	70	60
Total	**364**	**484**	**434**	**720**	**535**

(1) This consumption includes that of the energy sector (Eurodif, refineries, network losses, etc.)
(2) Taken from the « Energy 2010-2020 » report

In addition to the final consumption of electricity, the total electricity demand in France includes the needs of the energy sector itself, including consumption related to uranium enrichment, transmission/distribution losses and pumping.

The electricity demand related to the enrichment of uranium for French needs is presumed to stay constant (at 14 TWh) up until 2020, then drop to 0.2-0.4 TWh when a change takes place in the enrichment process. After that, demand is assumed to follow the evolution of electricity production using nuclear energy.

Indeed, the French enrichment plant, Eurodif currently uses the gaseous diffusion process to obtain uranium enriched with a maximum 5 % content of isotope 235. This process uses approximately 2 500 kWh per enrichment unit (UTS) i.e. given the current level of production at the plant, between 16 and 18 TWh a year [1].

The evolution of electricity consumption related to uranium enrichment will therefore depend :

- on the load factor of the enrichment plant, i.e. the evolution of the French and foreign needs ;
- on the lifetime of the plant, the plant having being commissioned over the period 1978-1982 ;
- on the process chosen in the event of re-construction of a new enrichment plant.

Shutdown of the plant was envisioned at a date between 2020 and 2030. Depending on the scenarios, it may be necessary to re-build one plant to cover the French needs for enrichment. If a new plant is needed, a different enrichment process will probably be chosen : either centrifugation, or isotopic separation using the laser method.

The first process, currently in use in several plants, is a mature process : the second process is still a the research phase. In our scenarios, we suppose that the new enrichment plant will use the ultra-centrifugation process, i.e. approximately 50 kWh per UTS.

The table below gives, for the different scenarios, an estimate, according to the conditions outlined above, of electricity consumption levels in 2020 and 2050 for the needs of uranium enrichment.

(1) For both French and foreign needs.

	2020 (Eurodif)	2050 (new plant)
H1	13.8 TWh	0.0 TWh
H2	13.8 TWh	0.25 TWh
H3	13.8 TWh	0.40 TWh
B2	11.8 TWh	0.18 TWh
B3	11.8 TWh	0.24 TWh
B4	11.8 TWh	0.0 TWh
B4-30	3.4 TWh	0.0 TWh

Given the envisioned levels of electricity demand in 2050, electricity consumption for the needs of enrichment will therefore be less than 0.1 % of the total demand for electricity, whereas that figure currently runs at over 3 %.

The switch from *total domestic electricity demand* over to *gross production per electric line* take into account the electricity used during the production of electricity (different according to the electric line) and of the following constraints and rules :

- in 2020, the gross production per electric line is that of the scenarios S2 and S3 of the « Energy 2010-2020 » report, from which we have deducted the gross nuclear production corresponding to the net electricity exports. The share of nuclear-based production remains constant at between 65 and 66 % (down from the 1995 figure of 76 %). In S2, the increased domestic demand is met by the development of co-generation and the putting onto the market of combined cycle systems with gas, which in 2020 supply 5 % of the electricity demand. The nuclear-based production remains constant at the 1995 level. In S3, the lower electricity demand can be met by the increased use of co-generation and wind generator systems, compensating for the reduction in nuclear-based production. The use of fossil fuels in the electricity sector reaches 16.2 Mtoe in S2 and 10.7 Mtoe in S3 ;

- for 2050, different supply scenarios will be prepared to meet all the electricity needs defined in the demand scenarios.

2. Electricity supply

To meet the needs of the two electricity demand scenarios, we prepared several contrasting scenarios for electricity supply, depending on a broad array of differing political and societal contexts.

In a ***first type of scenario***, we see a reduction in the level of State intervention in the economy and a re-definition of its modes of actions, working in the direction of broader trust in the self-regulating ability of market mechanisms. In this type of scenario, technical progress takes place against a background of an increasingly liberal market where there is very strong competition between production systems and minor environmental constraints. These scenarios therefore would not appear very favourable to nuclear energy.

In a ***second type of scenario***, the State becomes more interventionist in the economic and industrial domain, with the aim of identifying the long-term interests of the nation with the strength and competitiveness of its industry. This production-oriented attitude enables maintaining the nuclear system and promoting new electricity production systems.

In the ***third type of scenario***, the French State manages to impose nuclear energy despite a somewhat unfavourable international context.

In a ***fourth type of scenario***, the State primarily attempts to safeguard values such as the protection of public health, the prevention of technological risks and conservation of the environment, both on the local and global scale. The constraints it faces in doing so influence the limitation of greenhouse gas (GHG) emissions and issues of nuclear waste in a context where nuclear technologies will be abandoned throughout the world.

The environment component is clearly present in all of the scenarios, whatever their type. Only in the last category, however, does environmental conservation become the prime objective of the public authorities.

Finally, we cross-matched the demand and supply scenarios and came up with six different options :

- H1 = high-demand, “liberal” supply type 1
- H2 = high demand, “industrial” supply type 2
- H3 = high demand, “standalone” supply type 3
- B2 = low demand, “industrial” supply type 2
- B3 = low demand, “standalone” supply type 3
- B4 = low demand, “environmental” supply type 4

Scenario H1 corresponds to a market-driven logic with no major constraints in terms of controlling the demand, hence electricity consumption is high in a context where choices between systems are guided primarily according to their competitiveness on the international market.

In ***scenario H2***, France is determined to support the nuclear power industry with concerns relating essentially to the prosperity of the French firms in the international context, with no particular attempt being made to control electricity demand.

In ***scenario H3,*** the public authorities, for industrial or strategic reasons, seek to maximise the contribution of nuclear energy to the electricity supply, even if, to achieve that, they have to limit all factors that might moderate or influence the demand for electricity.

In ***Scenario B2***, concerns regarding the limitation of nuclear risks and other global environmental risks encourage factors that moderate and influence the demand for electricity, and the public authorities create a favourable context for a massive redeployment of industry and renewable energies.

Scenario B3 can be understood only if environmental constraints relating to the greenhouse effect become so crucial that any initiative to produce electricity independently of the non-nuclear mains electricity is discouraged in the face of surplus nuclear power production and flagging demand. In such a situation, the public authorities would seek to maximise the contribution of nuclear energy to overall electricity production while stimulating those actions that moderate or influence the demand for electricity and encouraging an extensive redeployment of the French industry in the domain of energy control and renewable energies.

In ***scenario B4***, strong concerns regarding the limitation of nuclear risks and other global environmental risks encourage factors that moderate and influence the demand for electricity, encouraging the public authorities to create a favourable context for a massive redeployment of the French industry in the domain of energy control and renewable energy sources. In such a configuration, we prepared an alternative scenario B4 (30 years) in which the lifetime of the existing nuclear power plants would be limited to 30 years.

2.1. The supply structure corresponding to the scenarios

Several hypotheses for the average lifetime of the current fleet of power plants were considered in Chapter 1.

In the remainder of this work we favoured, for the central hypotheses, an average lifetime of 45 years [1] ***for the existing fleet of power plants***. This average value was the median of a gaussian curve : i.e. with an average lifetime of 45 years, 5 % of the reactors are shut down at 35 years, 20 % at 40 years, 45 % at 45 years and 30 % at 50 years.

In an alternative version of the scenario B4, we considered [2] a hypothesis of a much shorter average ***lifetime*** of 30 years.

Time history of nuclear shut down (max net installed GWe)

Gross power	ALT (1) 30 yrs	ALT 45 yrs
2000-2010	5.3	0
2010-2015	31.6	0.8
2016-2020	15.0	7.4
2021-2025	5.3	19.9
2026-2030	5.9	19.3
2031-2035	-	8.5
2036-2040	-	4.0
2041-2045	-	3.0
2046-2050	-	-
Total	**63.1**	**63.1**

(1) ALT : average life time

In the ***first scenario H1***, the choice of electric lines is essentially guided by the economic competitiveness of each of them. We hypothesised a rapid breakthrough of combined cycles with natural gas (CCNG) : those systems supply 73 % of the electricity produced in 2050 alongside co-generation which

(1) A 32-year lifetime is indicated in the documents remitted to the French nuclear regulatory authority in the case of utilisation at full power, i.e. a lifetime of 40 years in the case of operation at 80 % capacity and 46 years in the case of operation at 70 % capacity, and this without prejudice to any future decisions to be made by the nuclear regulatory authority, particularly on the occasion of the ten-year inspections of the nuclear reactors.

(2) This scenario differs from the one envisioned by Germany in the June 2000 agreement. Indeed, in view of the hypotheses used for French electricity demand, scenario B4-30 results in a production equivalent to operation at full power for 19.7 years, whereas the scenario attached to the German agreement results in a production equivalent to operation at full power for 23.8 years. If the German nuclear fleet was operated under similar conditions to those of the French fleet, this would result in an average service life of 36.2 years instead of the 32 years used in the German agreement dated June 2000 (see the appendix two).

supplies almost 13 % during that same year. In this scenario, no new nuclear plants are constructed once the existing plants reach the end of their lifetime : the launch of CCNG onto the market compensates for the nuclear reactor capacities gradually as these facilities are shut down.

TWh	**1995**	**2020 S2**	**2025 H1**	**2030 H1**	**2035 H1**	**2040 H1**	**2045 H1**	**2050 H1**
Hydro	76	73	74	74	74	74	74	74
Nuclear	359	377	380	303	182	75	33	-
Others	37	100	130	252	415	564	646	719
Coal	22	4	-	-	-	-	-	-
Fuel + fuel turbine	2	10	10	10	10	10	10	10
Blast furnace gases	2	-	-	-	-	-	-	-
CCNG	-	28	50	160	311	448	518	579
auto, co-gen	11	40	50	60	70	80	90	100
wind	-	7	8	8	9	9	10	10
miscellaneous	-	12	13	14	16	17	19	20
Total supply	**471**	**551**	**584**	**629**	**671**	**714**	**754**	**793**

Natural gas consumption in the electricity sector in this scenario reaches 95.8 Mtoe by 2050 (as compared to a total consumption of 33.7 Mtoe of natural gas in all of the French economy in 1998).

In ***scenarios H2***, the State rapporting for the nuclear power industry keeps nuclear-based electricity production at a constant level close to the 1995 level. However, instead of supplying more than 76 % of net electricity production, nuclear energy production supplies only 44 % in 2050, so that almost all of the remaining electricity is produced by combined cycle (almost 29 %) and co-generation (12.6 %) systems. Nuclear power plants supply most of the base-load production (50 % of the electricity flowing through the main transmission networks).

TWh	1995	2020 S2	2025 H2	2030 H2	2035 H2	2040 H2	2045 H2	2050 H2
Hydro	76	73	74	74	74	74	74	74
Nuclear	359	377	380	284	301	318	333	348
Others	37	100	172	270	297	324	349	374
Coal	22	4	-	-	-	-	-	-
Fuel + fuel turbine	2	10	10	10	10	10	10	10
Blast furnace gases	2	-	-	-	-	-	-	-
CCNG	-	28	91	176	190	204	216	229
Auto, co-gen	11	40	50	60	70	80	90	100
Wind	-	7	8	10	11	12	14	15
Miscellaneous	-	12	13	14	16	17	19	20
Total supply	**471**	**551**	**584**	**629**	**672**	**715**	**755**	**795**

The continuous net nuclear power for French needs would drop from 61.7 GWe in 2000 to 47 in 2050. New equipment would displace the nuclear reactors leaving the market by and after 2030. Combined cycle systems in this scenario account for almost 30 % of production in 2050. Gas consumption for the production of electricity in this scenario would amount to 45.7 Mtoe.

In ***scenario H3***, the public authorities continue to favour nuclear energy as the prime source for electricity production : nuclear plants, which supplied more than 76 % of the net electricity production in 1995 would still represent almost 70 % in 2050 (compared to less than 16 % for natural gas). This situation therefore requires the construction of new nuclear reactors in 2025 to achieve a fleet of 85 GWe capacity in 2050. In this scenario, natural gas consumption for electricity production remains very low (13 Mtoe for co-generation with gas and only 3.6 Mtoe in the combined cycle systems).

TWh	1995	2020 S2	2025 H3	2030 H3	2035 H3	2040 H3	2045 H3	2050 H3
Hydro	76	73	74	74	74	74	74	74
Nuclear	359	377	407	437	467	497	526	556
Others	37	100	103	118	131	145	155	165
Coal	22	4	-	-	-	-	-	-
Fuel + fuel turbine	2	10	10	10	10	10	10	10
Blast furnace gases	2	-	-	-	-	-	-	-
CCNG	-	28	23	26	27	28	27	25
Auto, co-generation	11	40	50	60	70	80	90	100
Wind	-	7	8	8	9	9	10	10
Miscellaneous	-	12	13	14	16	17	19	20
Total supply	**471**	**551**	**584**	**629**	**672**	**715**	**755**	**795**

The four other scenarios are situated in the low-demand hypothesis.

In ***scenario B2***, some new nuclear reactors are launched onto the market 2030 or 2035 : with 33 GWe, they represent almost 40 % of the existing capacity in 2050 and during that same year supply 42 % of the electricity production (half of the electricity flow through the bulk transmission network). The presence of nuclear energy does not inhibit the gradual development of combined cycles with a capacity of almost 17 GWe in 2050 (more than 20 % of the entire production). In this scenario, gas consumption would reach 30.4 Mtoe in 2050.

TWh	1995	2020 S3	2025 B2	2030 B2	2035 B2	2040 B2	2045 B2	2050 B2
Hydro	76	73	74	74	74	74	74	74
Nuclear	359	337	281	228	233	238	242	246
Others	37	86	148	222	235	248	260	272
Coal	22	1	-	-	-	-	-	-
fuel + fuel turbine	2	6	5	5	5	5	5	5
blast furnace gases	2	-	-	-	-	-	-	-
CCNG	-	-	53	116	118	120	121	122
auto, co-generation	11	52	60	68	76	84	92	100
wind	-	17	18	20	21	22	24	25
miscellaneous	-	10	12	13	15	17	18	20
Total supply	**471**	**494**	**504**	**523**	**542**	**560**	**576**	**592**

In ***scenario B3***, the public authorities are successful in promoting nuclear energy in a situation of increasingly tough environmental constraints relating to the greenhouse effect. Some new, high capacity nuclear plants are built in 2030 or 2035 and with 47 GWe represent 60 % of the available electricity production capacity in 2050. The combined cycle capacities remain very low, which limits the consumption of natural gas to 17.1 Mtoe in 2050.

TWh	**1995**	**2020 S3**	**2025 B3**	**2030 B3**	**2035 B3**	**2040 B3**	**2045 B3**	**2050 B3**
Hydro	76	73	74	74	74	74	74	74
Nuclear	359	337	302	307	313	319	325	330
Others	37	86	128	142	155	167	178	188
Coal	22	1	-	-	-	-	-	-
fuel + fuel turbine	2	6	5	5	5	5	5	5
blast furnace gases	2	-	-	-	-	-	-	-
CCNG	-	-	34	38	40	42	43	43
auto, co-generation	11	52	60	68	76	84	92	100
wind	-	17	18	18	19	19	20	20
miscellaneous	-	10	12	13	15	17	18	20
Total supply	**471**	**494**	**504**	**523**	**542**	**560**	**576**	**592**

In ***scenarios B4-45 yrs*** and ***B4-30 yrs*** because of the constraints bearing on nuclear energy, no reactors are renewed after they reach the end of their lifetime (45 or 30 years). Gas massively displaces nuclear power production. Gas consumption then exceeds 70 Mtoe in 2050 in both scenarios. An additional effort is made to develop renewable energy technologies (30 TWh of wind generated electricity in B4 as against 20 TWh in scenario B3 in 2050).

B4-45 yrs

TWh	1995	2020 S3	2025 B4	2030 B4	2035 B4	2040 B4	2045 B4	2050 B4
Hydro	76	72	76	76	76	74	74	74
Nuclear	359	337	285	236	182	75	33	-
Others	37	86	142	211	283	409	467	516
Coal	22	1	-	-	-	-	-	-
fuel + fuel turbine	2	6	5	5	5	5	5	5
blast furnace gases	2	-	-	-	-	-	-	-
CCNG	-	-	36	82	131	234	270	296
auto, co-generation	11	52	69	86	103	121	138	155
wind	-	17	19	21	24	26	28	30
miscellaneous	-	10	13	17	20	23	27	30
Total supply	**471**	**494**	**504**	**523**	**541**	**558**	**574**	**590**

B4-30 yrs

TWh	1995	2020 S3	2025 B4	2030 B4	2035 B4	2040 B4	2045 B4	2050 B4
Hydro	76	72	76	76	76	74	74	74
Nuclear	359	82	40	11	-	-	-	-
Others	37	340	387	436	465	484	500	516
Coal	22	11	-	-	-	-	-	-
fuel + fuel turbine	2	6	5	5	5	5	5	5
blast furnace gases	2	-	-	-	-	-	-	-
CCNG	-	244	281	306	313	310	303	296
auto, co-generation	11	52	69	86	103	121	138	155
wind	-	17	19	21	24	26	28	30
miscellaneous	-	10	13	17	20	23	27	30
Total supply	**471**	**494**	**504**	**523**	**541**	**558**	**574**	**590**

In each of the scenarios, we assumed between now and 2050 :

- the fitting up of a dispersed electricity production capacity [1] of 100 TWh. In scenario B4 we added to this dispersed electricity production capacity a dispersed co-generation and/or own production capacity enabling the production of 50 TWh (fuel cells, gas microturbines at the foot of buildings, etc.) ;

(1) We recall that the electricity is referred to here as « dispersed » when it does not transit via the 400 KV or 225 KV bulk transmission network.

- a hydro-power production capacity stabilised at 74 TWh (75 in 1995) ;
- the abandonment in France of electricity production using coal and a switch to natural gas because of the major constraints on greenhouse gas emissions related to the use of coal.

In this decentralized electricity production capacity, several different technologies co-exist, whose presence in the future power generation fleets is favoured by the liberalisation of the European energy markets.

The competition that accompanies the globalisation process should logically result in a search for efficiency gains. Competition will therefore contribute to price reductions over the long-term. Each energy supplier must make efforts to be competitive, which implies finding new ways to reduce costs. Competition is an excellent driving force for technical process. However, at the same time, we must not under-estimate risks of collusion, which can generate unearned income and interfere with the price reductions. The mega-mergers currently taking place in the energy sector may eventually seem to look like a contributing factor to a monopoly situation in which the State's role will specifically be to ensure a minimum of competition for all contracts. Liberalisation, that is opening the main industrial segments of the grid to competition, should logically lead to broadening the field of the technological possibilities, since there will always be major players alongside smaller, independent operators. The technological options will indeed probably differ depending on the size of the players present in each segment.

2.2. The chosen mix of nuclear plants in the forecast scenarios

In the previous paragraph we defined seven electricity supply scenarios {H1, H2, H3, B2, B3, B4 (45yrs) and B4 (30yrs)}. In three of them {H1, B4 (45) and B4 (30)} the nuclear power plants are not renewed on reaching the end of their lifetime. However, scenarios H2, H3, B2 and B3 imply a partial or total renewal of the nuclear power plants ; some even imply the construction of additional nuclear capacities : for instance in the scenarios calling for the long-term use of nuclear energy, the required production capacity in 2050 will be between 33 and 85 GWe, compared to 63 GWe available capacity in the year 2000.

Several « systems [1] » comprising different reactor types and different fuel types can potentially meet that demand. In our analysis, we took into account not only

(1) Here, the term « system » refers to a fleet that may consist of several different reactor types and fuel types.

the international context, the demand and the possible dates on which the new systems might be ready, but also the general public policy issues underpinning the supply scenarios (industrial policy, safe source of energy supply, quality of life and environment).

As a result of cross-matching these diverse considerations we settled on eight different nuclear “systems” out of the many possible combinations [1] (see detailed analysis in the report prepared by the working group a “technological forecasts for nuclear options”).

In six of the scenarios, fuel-recycling operations are continued after 2010. In the two other scenarios, reprocessing stops in 2010.

Nuclear systems that imply the continuation of reprocessing operations

The six proposed nuclear systems present contrasting configurations for nuclear power generation and therefore the balance of materials.

All scenarios except F8 are based on pressurised water reactor systems (PWR, or its evolutionary version, the EPR). No major technological advances are anticipated on those systems, whose set-up costs and operating costs are the best known.

The systems are aimed at achieving better management [2] of the energy source, plutonium, and finding solutions to reduce the inventory of long-life ultimate waste, either through the development of fuels enabling multiple recycling of plutonium over an inert matrix (F2, F3) or through an improvement in the energy efficiency of the reactors (F4, F5, F8) by using new reactor systems to complement the EPR reactors, or by adjusting the neutron spectrum (F5).

Other systems were introduced to illustrate the scenarios where reprocessing stops.

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(1) The working group on « Technological forecasts for nuclear options » studied all of the systems. Their report is appended to this study.

(*2*) *– Proposing solutions based on multiple recycling, which enables stabilising the stock of plutonium from 2050 onwards while remaining within the fuel cycle (F2, F5), and thus reducing to almost zero the quantity of unusable plutonium contained in the spent fuels ;*

- by preserving the possibility of re-using the plutonium in the very long-term future by recycling the fertile materials (^{238}U and ^{232}Th) as energy resources.

By using different nuclear systems to address the same supply scenarios, it is possible to directly compare the material balances and the economic balances obtained with those systems.

The basic system : F1-EPR (UOX, MOX)

It is a system in which, starting at the 2020-2035 time frame and depending on the scenarios, the latest reactors of the current fleet of nuclear power plants co-exist alongside a new generation of reactors (EPR) using both UOX and MOX fuel. The plutonium from spent UOX fuels is recycled once, for use in MOX fuel, which implies the need to continue reprocessing as at present. In 2050, the fleet of nuclear power plants consists solely of EPR reactors. After the UOX has been recycled once, the spent MOX is placed in long-term storage (for approximately 150 years) prior to ultimate disposal or possible re-use. The category B waste from nuclear generating operations and reprocessing, and the category C waste from reprocessing are both conditioned using the same methods as today and placed in ultimate disposal, after a cooling period.

The basic system is an evolutionary one, along similar lines to the current system and therefore implying no new technical or economic uncertainties. It will be used in the economic analysis of all scenarios chosen in Chapter 5 below to address the electricity production capacity needed in 2050.

From that basic system, we considered two other systems using the same European Pressurised Reactors to renew the fleet of nuclear power plants, yet with new fuels.

System F 2 {PWR (UOX, MOX), EPR (APA)}

This system consists of the current PWRs plus EPRs as from the 2020-2035 time frame, as in the previous case. Like today's nuclear power plants and up until the 28 CP reactor [1] 1 and 2, they use UOX and MOX and then, for the EPR fleet, UOX and APA fuel [2]. That system, which presumes multiple recycling of

(1) The 900 MWe reactors were built under the scope of three successive programme contracts (contrat de programme, or CP in French) : CP0, CP1, CP2 : only the 16 reactors built under CP1 were authorised from the outset to use MOX. A new decree authorising the 12 reactors of CP2 to use MOX has still to be signed. 4 of the reactors obtained that authorisation, in 1998.

(2) The APA fuel (advanced plutonium assembly) is manufactured from plutonium obtained by reprocessing the MOX fuels produced in today's reactors, then after shutdown of the 28 CPI and CP2 reactors, by the reprocessing of UOX fuels

the fuel, implies the availability of spent MOX reprocessing capacities as from 2018 and spent APA reprocessing capacities as from 2030. It implies only minor changes to the fleet of nuclear plants yet requires the development and smooth operation of an entirely new fuel technology. The system leads over the long term to a reduction in the stock of unusable plutonium.

System F3 MOX, thorium

This system also consists of the existing PWRs and EPRs yet from 2020-2030 through 2040 it burns UOX and MOX fuels. After 2040, the plutonium obtained by reprocessing the MOX fuels is recycled a second time in the EPRs, in the form of a new MOX fuel based on plutonium and thorium oxide (MOX Pu-Th).

This system, which proposes recycling the plutonium twice to remove as much plutonium as possible before the spent fuels are sent for ultimate disposal, requires the installation of a new fuel manufacturing capacity and also presumes a considerable research effort.

From the same basic system (F1-EPR), we also studied two systems that in addition to the PWRs and EPRs introduce a new, more efficient reactor component (RHR 1 and 2) intended to use the plutonium from the spent fuels, more quickly and more efficiently.

System F4 RHR 1

This first system has the same common structure as the basic system (PWR, EPR, UOX, MOX) through to 2030. After 2030, some first-generation high performance reactors running on plutonium (from the reprocessing of MOX) confined within an inert matrix, are introduced into the fleet of reactors. The RHR 1 reactor fleet is designed to burn the quantity of plutonium obtained from spent MOX produced by the basic system. After 2030, that solution requires the introduction onto the market of a new generation of reactors built to the design of the prototype currently being studied for the elimination of military plutonium and mono-recycling of MOX.

System F5 RHR 2

This system comprises the same elements as the basic system through to 2040. After that date we assume the introduction of a new reactor component based on second-generation high performance reactors which perform better than the first generation in terms of energy efficiency and the combustion of plutonium and minor actinides. That new component is designed to recycle the plutonium obtained from reprocessing MOX fuels and therefore maintain a constant plutonium stock from approximately 2070 onwards.

It supposes the technical design and industrial development of a second generation of reactors, which implies a more ambitious research programme than in the RHR 1 system.

System F8 REP, RHR 1

In this, an alternative version of system F4, we continue to reprocess the UOX to manufacture MOX used in the PWRs (CP 1 and 2) through to the end of their ***lifetime***. Then in 2030, the EPRs are displaced by a newly introduced component consisting of high performance reactors (RHR 1) for an installed capacity of 33 GWe. MOX from the earlier fleet of power plants is reprocessed to supply the RHR 1 reactors with plutonium until the stock runs out (in about 2050), after which those RHR 1 reactors are supplied with a uranium fuel enriched with 20 % of ^{235}U.

Systems where reprocessing stops in 2010

Two systems are envisioned :

System F 6 EPR, UOX

It uses the same reactors (PWR and EPR) as the basis system but abandons the use of MOX after the reprocessing operations are shut down in 2010.

System F7 REP, RHR 1

It uses the existing PWRs only, up until the emergence (around 2030) of high performance reactors capable of directly burning 20 % enriched uranium more efficiently than the PWRs, which they progressively displace.

The table below summarises the various nuclear options taken up, and the scenarios chosen for the material and economic balances :

Future system	**F1**	**F2**	**F3**	**F4**	**F5**	**F6**	**F7**	**F8**
Reactors for the future fleet	EPR	EPR	EPR	EPR RHR 1	EPR RHR 2	EPR	RHR 1	RHR 1
Fuels loaded in the future fleet	UOX MOX	UOX APA	UOX MOX Pu MOX Th	UOX MOX Pu RHR1Pu	UOX MOX Pu RHR2Pu	UOX	U (20 %)	RHR1Pu RHR1 U
Fuels of the future fleet reprocessed	UOX	UOX APA	UOX MOX Pu	UOX MOX Pu	UOX MOX Pu	-	-	
H1	Nuclear power production abandoned after the 45 year mean lifetime of the existing reactors ; reprocessing stops in 2020							
H2	**X**	**X**	-	-	-	-	-	-
H3	**X**	-	-	-	**X**	-	-	-
B2	**X**	-	-	-	-	-	**X**	**X**
B3	**X**	-	-	-	-	-	-	-
B4	Nuclear power production abandoned after the 45 year mean lifetime of the existing reactors ; reprocessing stops in 2010							
B4-30	Nuclear power production abandoned after the 30 year mean lifetime of the existing reactors ; reprocessing stop in 2010							

In comparing the material and economic balances, our presentation will be oriented towards scenarios : H1 (no new nuclear equipment) ; H2 + F1 (EPR), H2 + F2 (EPR,APA), H3 + F5 (EPR, RHR 2), B2 + F8 (PWR, RHR 1, Pu + U), B2 + F7 (PWR, RHR 1, U 20 %), B4-45 and B4-30 (no new nuclear equipment).

2.3. The corresponding electricity production capacities

The tables and graphs below illustrate the evolution of the installed production capacities between 2000 and 2050 to supply the electricity needed in each of the scenarios we have described.

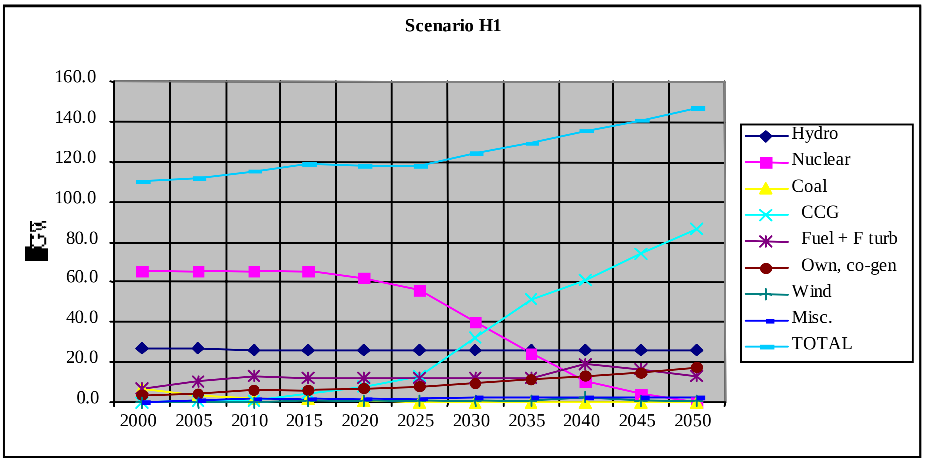
The forecast capacities take into account the load curve for electricity supply in the scenarios and the load factor of the different means of electricity production in each of the chosen systems.

High-demand scenarios

Scenario H1

This is the only scenario where electricity consumption is high and which does not envision renewal of the existing fleet of nuclear facilities at the end of its lifetime (45 years).

Scenario H1 : evolution of the installed capacities



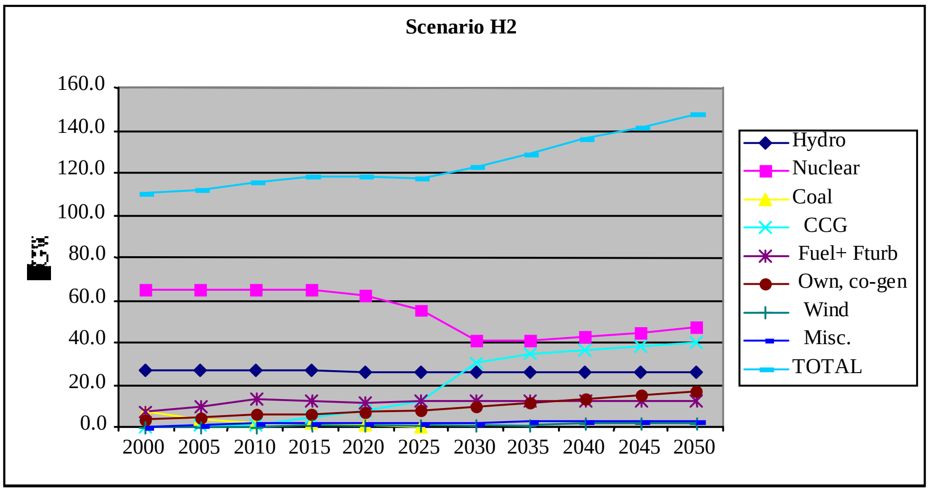
In a scenario such as this, the combined cycles with natural gas take over from the current nuclear power plants to supply base-load electricity via the very high voltage transmission network. With this system alone, that capacity amounts to over two-thirds of the total installed capacity (excluding hydropower). Alongside of that, we observe a strong progression of the smaller capacity installations, decentralized own generation and co-generation (engines and gas turbines, micro-turbines or fuel cells) systems whose capacity increases from 0.5 GWe in 2000 to 17 GWe in 2050. The combustion turbines intended to cover the peak-load needs remain fairly constant over the entire period. Lastly, we see the introduction of a wind generating capacity of 1.2 GWe full power equivalent, 10 TWh between now and 2050.

Scenario H2

This scenario calls for a renewal of the existing nuclear reactors to the measure that the fleet can produce approximately 50 % of the electrical energy in 2050 transiting via the electricity bulk transmission network. This supposes the introduction of new capacities to gradually renew the current facilities and attain in 2050 a capacity of 47 GWe. That nuclear capacity can be achieved using several of the systems envisioned earlier (F1, F2, F3, F4, F5, F6).

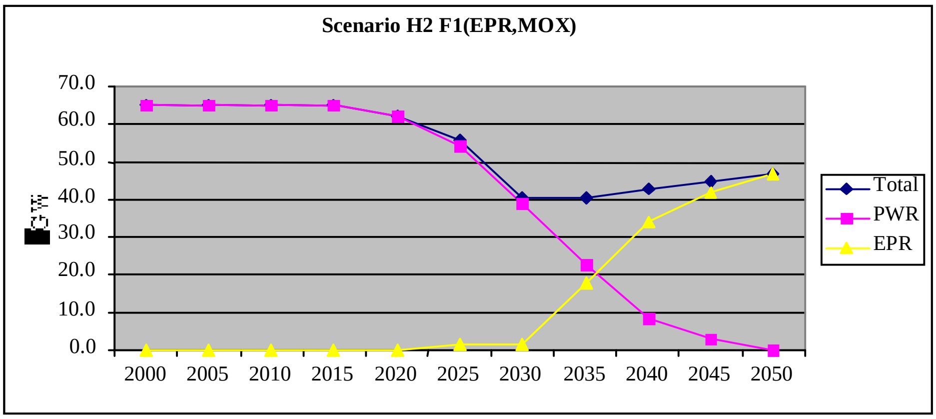
The graph below shows for scenario H2 the evolution of all the nuclear capacities, with no discrimination between the different nuclear systems.

Scenario H2 : evolution of the installed capacities



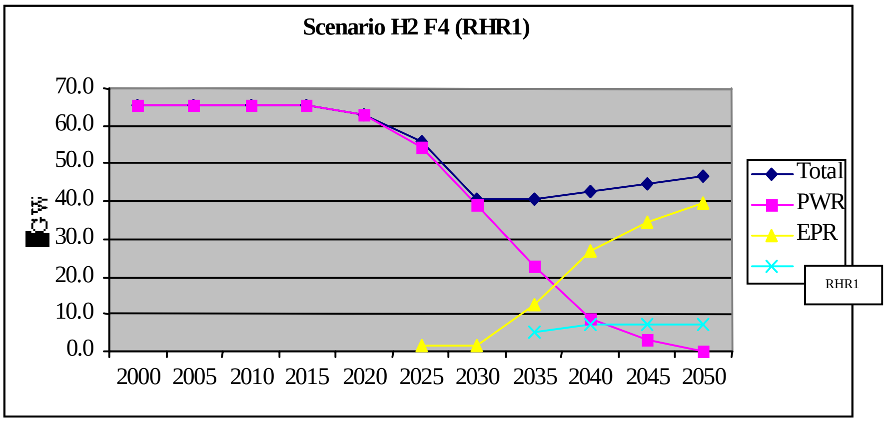
In this scenario, the capacity of the gas turbines with combined cycle, although less than that used in H2 amounts to almost 40 GWe in 2050. The evolution of the other capacities (fuel turbine (TAC), co-generation, etc.) is similar to that of H1. Wind generation capacity is increased to 1.8 GWe in 2050.

Scenario H2 (EPR, MOX) : evolution of the nuclear capacities
(valid for F1, F2, F3, F6)



In this scenario, the first EPRs displace the obsolete PWRs starting in 2030-2035 to reach a capacity of 47 GWe in 2050. The evolution here is the same as for the capacities of systems F2 (APA), F3 (MOX Th) and F6 (UOX). For instance, in the above graph we show the evolution of the installed nuclear capacities if, starting in 2030 – 2035, both EPR and RHR1 reactors are introduced into the fleet of reactors to burn the plutonium obtained from the reprocessing of spent MOX fuel. At the end of the period, the fleet comprises 40 GWe of EPRs and 7 GWe of RHR1 (high performance) reactors.

Scenario H2 F 4 (EPR MOX, then RHR 1)
evolution of the nuclear capacities

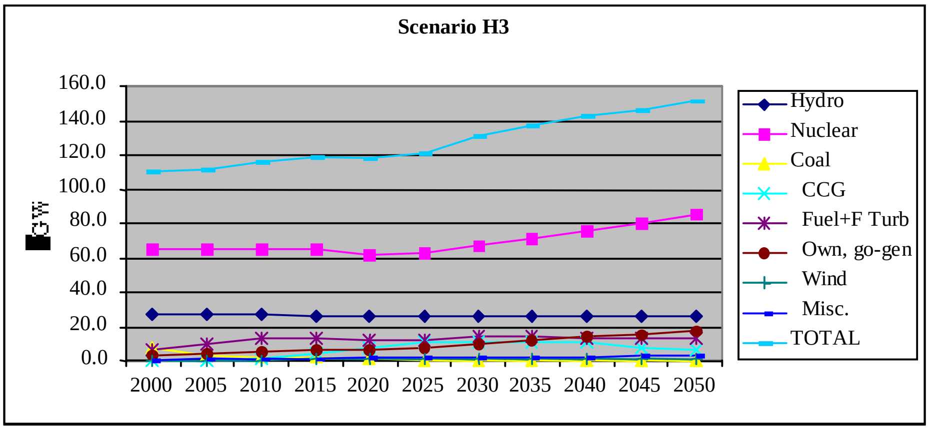


Scenario H3

This scenario calls for a renewal of the current nuclear power plants so as to be able to supply 80 % of the electrical energy transiting through electricity bulk transmission network by 2050.

This supposes the introduction of some capacities to progressively renew the current fleet, and after that, the introduction of some additional capacities to reach a total capacity of 85 GWe in 2050.

Scenario H3 : evolution of the installed capacities



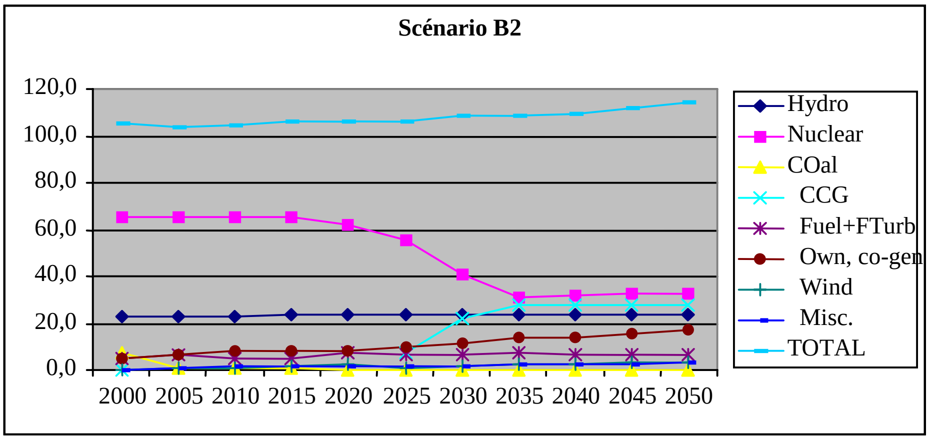
In this scenario, the combined cycles with natural gas account for only a negligible part with 6 GWe in 2050. The other means of production : fuel turbine with domestic fuel oil (TAC FOD), own production and co-generation, wind generation, follow the same evolution as in the previous scenarios. As regards nuclear reactors, the first EPRs are introduced in 2025. In the alternative version comprising high performance second-generation reactors (system F5), the RHR2 reactors are introduced towards 2040. At the end of the study period (2050) the fleet comprises 63 GWe of EPR reactors and 22 GWe of RHR 2 reactors.

Low-demand scenarios

Scenario B2

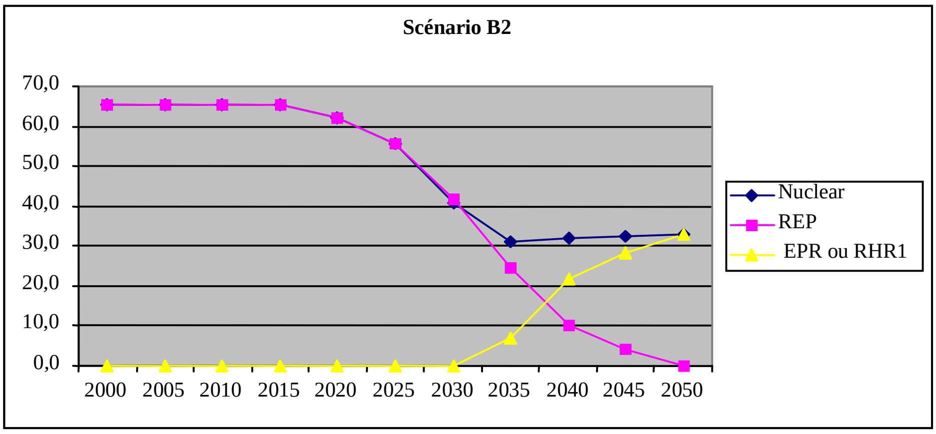
In this scenario where electricity consumption is low (590 TWh in 2050 compared to 795 TWh in the high-demand scenarios), the existing nuclear fleet is renewed to the measure that it can supply almost 50 % of the electricity transiting in the electricity bulk transmission network in 2050. This supposes the installation of sufficient capacity to renew the existing fleet progressively as from 2030-2035 and to achieve a capacity of 33 GWE nuclear power production in 2050.

Scenario B2 : evolution of the installed capacities



In such a scenario, which combines a 45 year lifetime for the existing reactor fleet and a lower demand for electricity, we can consider displacing the existing fleet over the period 2030-2035 either with EPR reactors or with an entirely new generation of high performance reactors RHR 1 which, at the end of the period, compose the entire installed capacity.

Scenario B2 : evolution of the installed nuclear capacities

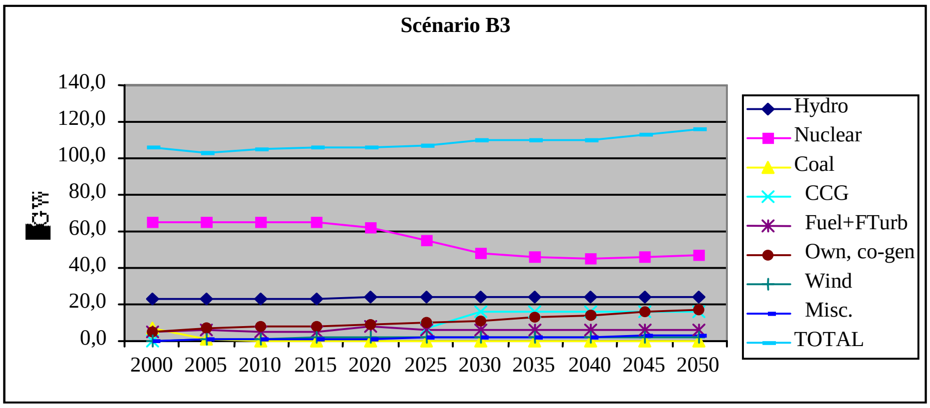


Scenario B3

This scenario calls for renewal of the current nuclear reactors to the measure that the new fleet can meet approximately 80 % of the power transiting via the electricity bulk transmission network in 2050.

This supposes the gradual introduction of capacities to renew the current fleet and achieve by 2050 a nuclear capacity of 47 GWe (equal to the capacity chosen in H2).

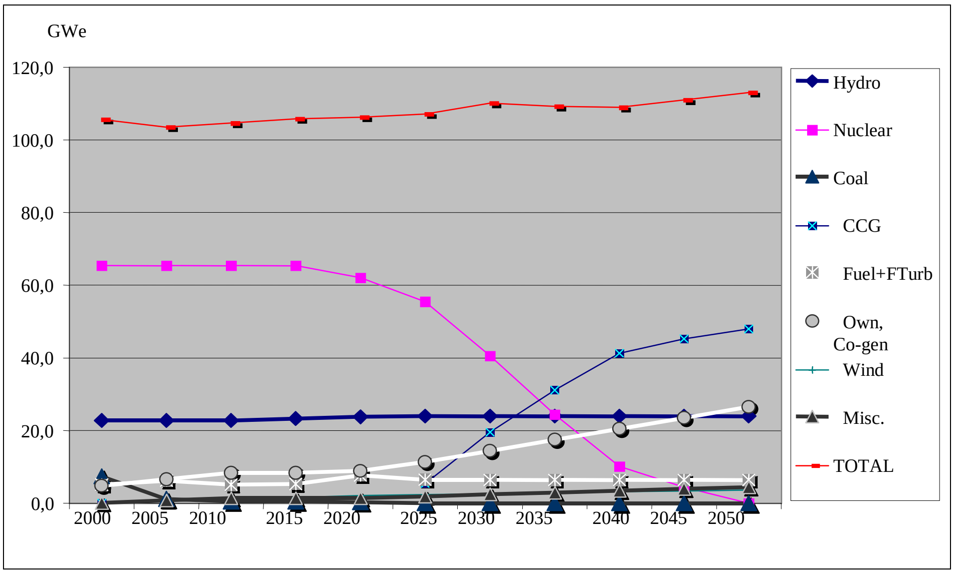
Scenario B3 : evolution of the installed capacities



Scenarios B4-45 yrs and B4-30 yrs

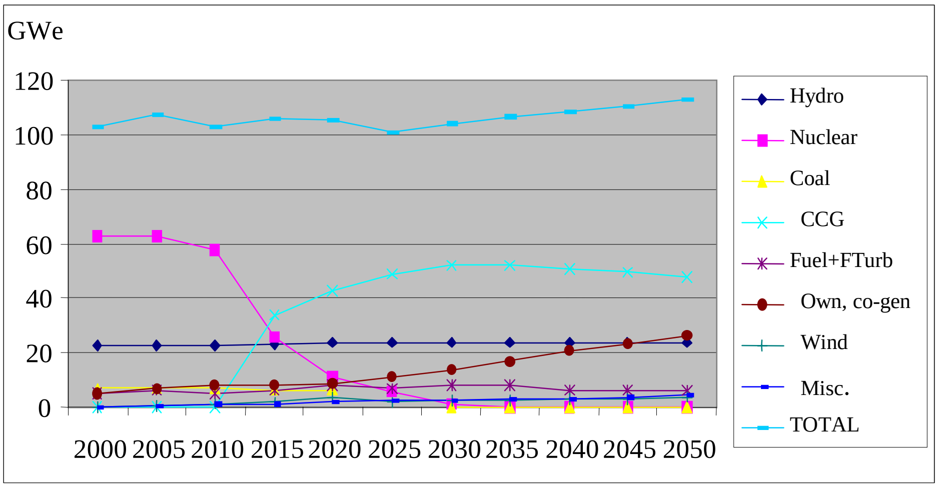
In these two scenarios, the current nuclear fleet is not renewed at the end of its average lifetime (45 years or 30 years). Those reactors are displaced by combined cycle systems with natural gas as from 2025 in the 45-year scenario and as from 2010 in the 30-year scenario. Also, because of the greater contribution in the other scenarios of own generation and co-generation : the own generation and co-generation capacities amount to an installed capacity of 26.5 GWe in 2050 as against 17 GWe in the other B scenarios. Wind generation and miscellaneous systems (waste, timber energy source, etc.) respectively amount to 3.6 and 4.4 GWe in 2050 compared to 2.4 and 3 GWe in the other scenarios.

Scenario B4 (45 years) : evolution of the installed capacities



In scenario B4 (30 years), gas turbines with combined cycle are brought on the market earlier, as shown in the graph below. Starting in 2020, the capacity of the combined cycles with gas (CCG) amounts to over 40 GWe, a value attained only 20 years later in scenario B4 (45 years).

Scenario B4 (30 years) : evolution of the installed capacities



3. The corresponding material balances

The scenarios present contrasting material balances in 2050, whether as regards :

- cumulative totals of the fossil and fissile fuels used over the period 2000 to 2050 ;
- the stockpile of nuclear wastes (waste and spent fuels) or the cumulative total of CO_2 emissions over the period.

We chose to compare those balances by selecting the following parameters for each of the scenarios :

- cumulative total of natural gas, coal and oil used between 2000 and 2050 ;
- cumulative total of carbon gas emitted (expressed as carbon equivalent) between 2000 and 2050 ;
- cumulative total of plutonium + minor actinides [1] unused in 2050 ;
- cumulative total of electricity produced over the period 2000 to 2050.

We also indicated the cumulative totals of carbon and transuranium elements in the different scenarios between 1977 (when the PWR programme first started), and 2050.

The following table collates all this information for the different scenarios, after first assuming the systematic use of the base system F1 (EPR) in all scenarios based on the hypothesis of the renewal of the fleet of nuclear plants.

(1) In this paragraph, we will use the terms « transuranians » and « plutonium + minor actinides » knowing that, by definition, the transuranians are heavier chemical elements than uranium (atomic number 92). The main transuranians are : neptunium (93), plutonium (94), americium (95) and curium (96).

	H1	H2	H3	B2	B3	B4	B4-30
Fuels							
Natural gas (Mtoe)	1 784	1 233	621	748	704	1 340	2 196
Oil (Mtoe)	95	95	95	39	44	44	44
Coal (Mtoe)	72	72	72	19	19	19	57
CO_2							
CO_2 (Mt of C) 2000-2050	1 425	1 037	607	710	556	1 006	1 646
CO_2 total (Mt of C) 1977-2050	1 935	1 547	1 117	1 220	1 066	1 516	2 156
Transuranian elements							
Cumulative total transuranians (tonnes) 2000-2050	365	473	594	411	459	329	204
Electricity (TWh) 2000-2050	**30 625**	**30 650**	**30 650**	**26 180**	**26 180**	**26 150**	**26 150**
Cumulative total transuranians (tonnes) 1977-2050	495	603	724	541	589	459	334
Transuranians/TWh (kilo/TWh) 2000-2050	12	15.4	19.4	15.7	17.5	12.6	8
CO_2 /TWh (ktC/TWh) 2000-2050	46.5	33.8	19.8	27.1	21.2	38.5	62.9

N.B.1 : For the main scenarios, we will explain with greater precision the consequences of the use of alternative nuclear systems on the material balances
N.B.2 : We considered that : 1 toe of natural gas produces (average value) between now and 2050, 0.7 tonne of carbon including 8 % for extraction and transmission to the power plants ; 1 toe of fuel produces on average 0.89 tonne of carbon including 8 % for extraction and transmission ; 1 toe of carbon produces on average 1.15 tonne of carbon including 3 % for extraction and transmission

3.1. Cumulative total of carbon gas emissions

The differences between scenarios essentially bear on the use of natural gas, ranging from 621 to 2,196 Mtoe depending on the scenario.

The cumulative total carbon emissions between 2000 and 2050 evolve within a broad range (ratio of 1 to 3, between 556 and 1 646 Mt of carbon) between the extreme scenarios :

- they are smaller, and of a similar order of magnitude, in the two « standalone »scenarios **H3** (607 Mt) **and B3** (approximately 556 Mt) which call for the biggest nuclear capacity (56 to 70 % of the electricity production) ;

- they are higher in scenarios **H1 and B4-30 years** which have carbon emissions of 1 425 and 1 646 Mt respectively. In H1, electricity consumption is high and nuclear power production is abandoned after an average lifetime of 45 years ; in B4-30 yrs electricity consumption is lower, but nuclear power production is given up after only 30 years ;

- scenarios **H2** (high consumption, 44 % nuclear production in 2050) and **B4-45 years** (no renewal of the fleet) present the same intermediate results, for emissions (1 037 and 1 006 Mt).

These results show firstly the importance of the evolution of electricity demand on the cumulative total quantity of carbon : for instance, a high-demand scenario with 43 % nuclear production in 2050 (H2) gives out as much carbon as a scenario with more moderate demand, without renewal of the fleet of reactors and with a 45-year lifetime for the current fleet (B4). However, we must take into account that even in the scenario B4, the electricity from nuclear energy sources represents 46 % of the total cumulative electricity production, as compared to 55 % in the case of H2.

Of course, for a given electricity demand scenario, the cumulative total quantity of carbon diminishes gradually as the nuclear fleet increases.

Lastly, if we compare carbon emissions in the different scenarios, starting in 1977 when the PWR reactor programme first began, the range gets smaller but is still considerable : emissions amount to between 1 066 and 2 156 Mt of carbon in the extreme scenarios.

The differential stake of approximately 1 000 Mt in 2050 between the different scenarios should be compared with the more general stake of total cumulative emissions associated with the two energy scenarios : they amount to 5 600 and 7 400 Mt respectively in 2050 [1].

(1) Based on a total cumulative energy over the period 2000 to 2050 of 11 000 to 13 400 Mtoe in the low and high demand scenarios, including approximately 50 % of electricity (1 100 to 2 000 Mt of C) and 5 500 to 6 700 Mtoe of fossil energy sources emitting 4 500 to 5 400 MT of carbon.

3.2. Cumulative total of transuranium elements (plutonium and minor actinides)

The balances of transuranium elements (Pu + minor actinides) in 2050 also result in contrasts between the scenarios, and even within those scenarios, depending on the nuclear systems used (from 204 tonnes for scenario B4-30 years to 594 tonnes for scenario H3 EPR).

The following table presents the balances associated with the different alternatives envisioned in the high electricity demand scenarios.

Tonnes	H1	H2 EPR	H2 APA	H3 EPR RHR 2	H3 EPR
Accumulated transuranians 2000-2050	365	473	221	362	594

For the high-demand scenarios, the APA fuel solution in H2 gives the best results from the standpoint of the accumulation of transuranians between now and 2050 with a cumulative total of 221 tonnes compared to 473 in the basic solution (H2 EPR) and 365 in H1. Similarly, the alternative with RHR 2 in H3 brings that balance down from 594 tonnes in the basic solution (H3 EPR) to 362 tonnes.

We will see a noticeable difference in the situation at the end of the lifetime of the fleet of reactors present in 2050 in the different scenarios. This point will be discussed in more detail later.

The same exercise was carried out for the low-demand scenarios.

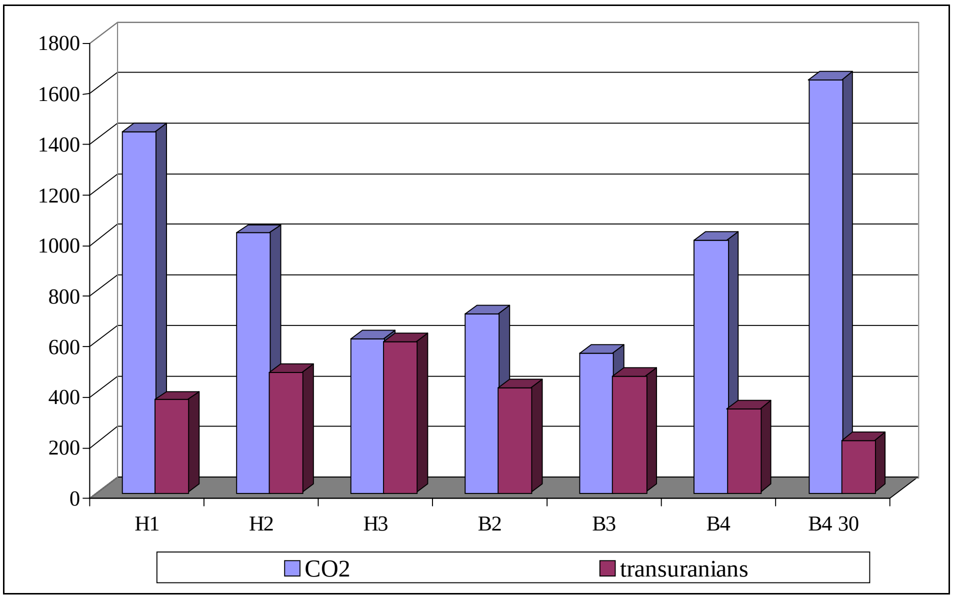
Tonnes	B2 EPR	B2 RHR 1 Pu + U	B2 RHR 1 U(20 %)	B3 EPR	B4	B4-30
Accumulated transuranians 2000-2050	411	115	583	459	329	204

Of those scenarios, B2 RHR 1 (Pu + U) results in the best material balance, with 115 tonnes in 2050 compared to 411 in the basic solution B2 EPR : indeed, in this scenario, the RHR reactors that are introduced use up all the plutonium contained in the spent MOX unloaded from the existing PWR reactors. However, in solution B2 RHR 1, with reprocessing stopping in 2010 and the reactors burning enriched uranium, we calculated the plutonium present in the non-reprocessed spent MOX and the plutonium present in the 20 % uranium-enriched spent fuel at the end of the study period and arrived at a cumulative total of 583 tonnes in 2050, i.e. a higher figure for emissions than in any of the other scenarios. Scenario B4-30 which gives up the existing reactor fleet after 30 years results in a material balance of 204 tonnes compared to 365 tonnes for scenario H1 and 329 for scenario B4.

These few examples of alternative versions of various scenarios to illustrate the stakes, in the event of new reactor systems or new fuels emerging at a later date, and their impact on the balance of materials between now and 2050.

The graph below shows the carbon emissions and balance of nuclear materials in the different scenarios, limited to the basic system F1 (EPR).

Cumulative total emissions between 2000 and 2050
carbon in millions of tonnes, transuranians in tonnes



We can also examine the performances of the different scenarios, comparing them to the cumulative total of electricity produced over the period.

The following table indicates the results obtained for carbon and nuclear materials in the basic case F1 (EPR) for the different scenarios.

2000-2050	H1	H2	H3	B2	B3	B4	B4-30
Transuranians/TWh (kg/TWh)	11.5	15	11.8	15.2	17.5	12.2	7.8
Carbon/TWh (kt/TWh)	46.5	33.8	19.8	27.1	21.2	38.5	62.9

It illustrates the compromise established between the performances per kWh in each of the scenarios, for the two environmental problems we decided to review here. The best scenarios from the standpoint of nuclear wastes (B4-30, H1 and B4) perform poorly in terms of cumulative emissions of greenhouse gases. H3 and B3 on the other hand, perform well in terms of greenhouse gas emissions yet less well with regard to nuclear wastes.

We can also compare the nuclear systems proposed in the scenarios to see where they "fit", by relating the cumulative total production of nuclear waste to the cumulative production of electricity over the same time frame. We did this for 3 time frames : 2000-2050, the period for which we conducted the economic balances, 2000-2070 the time frame that enables us to fully grasp the consequences of introducing the new systems, and lastly 2000 to the end of the reactor lifetimes, which enables determining the final situation after the shutdown of all power plants constructed before 2050. That is the purpose of the following table :

	H1	H2 EPR	H2 APA	H3 EPR RHR2	B2 RHR1 Pu + U	B2 RHR1 U(20 %)	B4	B4-30
Cumulative total (transuranians) 2000-2050 (tonnes)	365	473	221	362	115	583	329	204
kg/TWh nuclear (transu.) 2000-2050	26.5	26.5	12.4	16.2	7.4	37.6	26.5	34.9
Cumulative total (transuranians) 2000-2070 (tonnes)	365	631	221	321	238	678	329	204
kg/TWh nuclear (transu.) 2000-2070	26.5	25.3	8.9	9.8	11.6	33.2	25.7	34.5
Cumulative total (transuranians) 2000-end of lifetime (tonnes)	365	873	342	510	283	718	329	204
kg/TWh nuclear (transuranians) 2000-end of lifetime	26.5	26.8	10.5	11.7	12.7	32.4	25.7	34.5

2000-2050 time frame

With 7.4 kg of transuranium elements (Pu + minor actinides) per TWh, the B2 RHR1 (Pu + U) system appears to perform the best from the standpoint of the material balance over the 2000-2050 time frame. It is followed by H2 APA (12.4 kg) and the H3 RHR 2 system, the real advantages of which are not seen until later.

2000-2070 time frame

In 2070 the material balances of the different scenarios as situated within a range of 1 to 3.3 as regards the cumulative total of transuranians (204 to 678 tonnes). Outside of scenario B4-30 which hypothesises the shutdown of the current fleet of reactors after 30 years (204 tonnes), it is the APA system in H2 (221 tonnes) which gives the best result, slightly ahead of the RHR1 system in H2 (238 tonnes). If we compare those balances to electricity production over the same time frame, we notice that system H2 APA yields the best results (8.9 kilos per TWh), ahead of the H3 RHR2 system (9.8) and B2 RHR1 (Pu + U) (11.6).

2000 – end of lifetime (2110)

In 2110 the material balances in the different scenarios for the cumulative total transuranians lie within ranges of 1 to 4. Beyond scenario B4-30 which displays the best performances (204 tonnes), once again it is the RHR1 system in B2 which has the lowest material balance over that time frame (283 tonnes), ahead of B4 (329 tonnes), the APA system in scenario H2 (342 tonnes), and H1 (365 tonnes). The performances of the RHR2 system in scenario H3 worsen, with 510 tonnes of accumulated transuranians in 2110 [1].

In terms of the quantities of waste accumulated per TWh from 2000 to the end of the reactor lifetimes in the different scenarios, the two systems H3 EPR RHR2 with 11.7 kilos per TWh and H2 APA with 10.5 kilos per TWh are more efficient that system B2 RHR1(12.7 kilos per TWh).

(1) This is due to the presumably shorter lifetime of the RHR2 reactors (40 years) than of the EPR reactors (60 years). As the RHR2 are shut down before the EPR, there will be a stockpile of transuranians.

The preceding table therefore illustrates the considerable reductions forecasted in the material balances as a result of electricity production from nuclear energy sources in the event of the emergence of the systems mentioned earlier [1].

The EPR systems using APA fuel, EPR + RHR1 (Pu + U) and EPR + RHR2, enable, in the case of a constant strategy pursued through to 2070, diminishing the material balance by a factor of approximately 4 compared to that of the basic system, the EPR (MOX). Over a shorter time frame (2050) the RHR1 enables diminishing the material balance by a factor of 3 compared to the basic solution.

(1) Study is currently in progress on the alternative RHR1, which intended to burn excess military plutonium. In the case of a moderate demand or a determination to abandon nuclear power production later, the introduction of RHR1 reactors burning the plutonium present in the existing spent MOX enables a rapid and significant reduction in the volume of transuranians (Pu + minor actinides) present in 2050. If the nuclear programme is pursued at a higher level, the introduction of RHR1 reactors downstream of the EPR reactors enables, by the end of the lifetime, a reduction in the materials balance by a factor of 3.4 compared to the EPR solution.

Chapter 5

The economic balance of different scenarios

The description of the electricity supply scenarios given in the previous chapter traced the variation in time of the main physical parameters (installed capacities, fuel quantities used, associated electricity generation and waste or emissions produced, treatment and storage capacities for the various waste, etc.), that are used in this chapter to determine economic cash flows in each scenario to the extent that reliable estimates of the corresponding unit costs can be determined. On the other hand, the capital investments and operating costs of the electricity saving measures necessary to change from high to more moderate electricity demand scenarios are not explicitly taken into account in the proposed evaluation. It is assumed here that the measures adopted do not cause any extra global cost (meaning the global cost over the total service life of economical equipment) for the different users in the regulatory and incentive context corresponding to the proposed scenarios. However, estimates of the extra costs of public policies necessary to make these electricity saving scenarios possible will have to be made.

1. Data preparation

We have various available data that we can use to prepare economic balances :

- investment histories for new electricity generation capacities ; histories of upkeep expenses for these capacities, if any ; histories of expenses incurred for dismantling of the installations ;
- investment histories for gas and electricity transmission networks necessary to supply production plants and for transmission of the electricity generated ;
- investment histories for the back-end of the nuclear fuel cycle (reprocessing plants, interim storage and ultimate disposal capacities, etc. ;
- fuel cost histories (natural gas, coal, fuel oil, uranium, etc.) ;

- operating cost histories of power stations, fuel cycle installations, interim storage and ultimate disposal facilities.

The basic principle for making the calculations consists of using precise knowledge or an evaluation of the variation of unit costs for each element included in these different cost items, to estimate the annual costs for each electrical system described through the different scenarios.

Finally, a first evaluation of the relative importance of some external factors (CO_2 emissions, waste, etc.) associated with scenarios can be made based on standard assumptions (cost of carbon and cost of transuranic elements), if the flows and stocks of emissions and waste produced in the different options in each of the scenarios are known.

2. Price scenarios for fossil fuels

In an attempt to identify limits to the range of possibilities, we have selected two contrasting images for the future price of oil by 2050, and three images for the price of natural gas. This actually led to three scenarios :

- a « *constant energy price* » scenario, in which the price of gas is indexed to a constant price of oil ;
- a « *break in conditions of relative prices* » scenario in which the price of gas increases despite a constant price of oil ;
- a « *tension on fossil energy prices* » scenario, in which the price of gas is indexed to a high price of oil.

These three scenarios are described in detail in the appendix.

Furthermore, the prices of fossil fuels purchased on international markets are expressed in dollars, consequently we needed to consider the variation in the dollar-french franc exchange rate over the period covered by our report.

When the technology considered uses fossil fuels purchased in dollars on international markets, the cost of these fuels expressed in local currency can have an important influence on the competitiveness of this technology compared with a technology for which the proportion of imported fuels is lower.

Assumptions have to be made about exchange rates within the period covered by our report, considering in particular that the proportion of imported fuels in the cost per kWh is high for combined cycle or co-generation technologies using gas. Rather than carrying out a study on how the two currencies vary with respect to each other in the very long term, in this report we will use the same convention as the main forecasting organisations (national and international) ; we will use a constant exchange rate over the entire period equal to the average of the purchasing power exchange rates calculated by the OECD. For the 1988-1998 period, this gives a value of one euro for one dollar.

Price of oil and natural gas (1 dollar = 1 euro = F 6.55)

	1999	2010	2020	2050
Price of oil $1999/barrel				
1 - Constant	17.4	20	20	20
2 - Tension on the market	17.4	28	30	40
Price of gas $1999/million Btu				
1.1 - Related	2.8	3.2	3.2	3.2
1.2 - Break in conditions	2.8	3.4	3.6	4.5
2.1 - Related	2.8	4.5	4.7	6.0

Source : les rapporteurs

For uranium, we used the assumptions given in chapter 1 : a slow increase in prices from 300 to 400 F/kg is assumed for the period 2000 to 2050.

Price of uranium

Uranium	2000	2010	2020	2030	2040	2050
F/kg	300	320	340	360	380	400

Source : CEA

3. Investment and operating costs for the various electricity generation options

The analysis of the variation in capital investment, operating and maintenance costs included detailed estimates for the main non-nuclear energy sources (particularly combined cycles with natural gas for which there is a great deal of current and forecast data), and more approximate estimates for technologies used marginally in the different scenarios (for example fuel cells and wind-powered generators). For the new nuclear systems, we simply estimated the EPR system for which fairly precise information is available (particularly for investment costs), and for the RHR1 system and the APA system, although the estimates are less accurate. Complete economic estimates have been made for the PWR (900 MWe, 1 300 MWe) and EPR systems.

3.1. Nuclear generating capacities

There is sufficient experience in France to accurately determine the various costs for the PWR systems.

The estimate for the EPR system is not quite as precise, but uncertainties are minor. Investment costs suggested by Digec [1] have been used, however assuming an extra cost of 30 % for the first reactor in a series, 20 % for the next two reactors, 10 % for the fourth reactor and then a unit cost equal to the cost suggested by Digec for subsequent reactors (for a series of 10 reactors).

For the RHR1 reactor, for which the prototype would be very similar to the HTR reactor currently being designed, we have assumed costs suggested by Framatome and the same cost reduction rule as was used for the EPR.

For the APA system, we have used estimates supplied by the CEA (*Commissariat à l'énergie atomique* - Atomic Energy Commission).

Other systems (high temperature second-generation reactors, MOX Th fuel) were not estimated as precisely. Due to the various uncertainties concerning them, we assumed for the purposes of this report that these new systems would become competitive with earlier systems, if the R & D work on them is successful (an attempt has been made to estimate the duration and financial cost of the R & D work).

Operating costs for existing facilities have been analysed starting from the current situation, as determined by EDF nuclear operations accounts and predicted progress, in particular taking account of productivity gains and management of units based on longer production campaigns between two fuel unloading operations. Current information provided by EDF [2] is sufficient to

(1) Source : « Reference costs for electricity generation » DGEMP May 1997.
(2) Note that EDF operating accounts include the first ten-year inspection of nuclear units (see below).

calculate operating costs using a formula containing a fixed term depending on the power of the installation, and a term proportional to production in the form :

Cost/kWh = 380 F/kWe + 0.5 centime/kWh [1]

We assumed that technical and organisational progress would make it possible to reduce the fixed operating cost of 100 Francs per kWe (280 Francs/kWe) at the end of the life of existing power stations, and consequently we used an average operating cost over the period for PWR reactors as given by the following formula :

Cost/kWh (PWR) = 330 F/kWe + 0.5 centime/kWh

For EPR power stations that have not yet been built, we used a similar formula assuming that the fixed operating cost would vary from 280 Francs to 190 Francs per kWe [2] between the appearance of the first reactors and 2050, with a fixed average cost of 235 Francs over the period (apart from the first ten-year inspection).

Therefore, operating costs for EPR system (including the first 10-year inspection) are given by the following formula :

Cost/kWh (EPR) = 240 F/kWe + 0.5 centime/kWh [3]

« Post-operation » costs incurred after the final stoppage of production but not included in dismantling costs, need to be added to these operating costs. They have been estimated at F 1 000/kWe distributed over 3 years for PWR and EPR plants, and F 800/kWe distributed over 2 years for RHR1 plants.

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(1) This cost is applicable to all nuclear power stations including those that generate exported electricity. The scenarios drawn up assume that exports will continue until 2020 (consistent with scenarios in the « 2010-2020 Energy report »), but do not consider possible export beyond 2020 in some scenarios in which electricity demand is lower than the capacity of installed power stations.

(2) The value of 190 Francs selected by Digec in reference costs for 2020 and 2025 would mean a significant reduction of operating costs for EPR units compared with existing PWR units. We used this value at the end of the period.

(3) Use of this formula for scenarios in which nuclear power is used for base supply (Kp = 85 %) gives operating costs (including insurance and the first ten-year inspection) equal to 3.7 centimes/kWh, to be compared with a cost of more than 6 centimes in 1998, with Kp equal to 70 %.

Finally, accident insurance for the nuclear option is treated differently to other options. The operator only takes insurance for amounts of up to F 200 millions for nuclear accidents, and independently builds up provisions to fund compensation of up to F 600 millions.

Assuming that the total coverage guaranteed by the French State and the pool of States concerned is equal to F 2,500 millions (including EDF's F 600 millions), the corresponding theoretical premium would be of the order of 500 millions francs per year [1]. We have assumed an annual insurance premium of F 10 millions/1 000 MWe unit in the rest of the chapter.

In the calculations carried out, this amount of F 10 /kWe is additional to the fixed operating costs of power stations, and consequently the averages are 340 and 250 F/kWe respectively over the period.

Furthermore, the following costs were assumed for upkeep and dismantling operations :

Upkeep F/kWe					
Time*	**10 years**	**20 years**	**30 years**	**40 years**	**50 years**
900 MWe PWR	300**	600	600	500	-
1 300 MWe PWR	300**	600	600	500	-
EPR (60 years)	200**	400	600	600	500
RHR1 (280 MWe)	400**	600	500	-	-

* *starting from commissioning*
** *the operating costs given above include the first 10-years inspection*

Dismantling	**F/kWe**
900 MWe PWR	1 700 - 2 000*
1 300 MWe PWR	1 700 - 2 000
EPR	1 700 - 2 000
RHR 1 (280 MWe)	3 000

* *depending on the dismantling calendar*

(1) Insurance premiums paid by EDF to insure against nuclear damage to property and persons are equal to 42 millions francs per year (for 58 reactors) ; this corresponds to a coverage of 200 millions francs (the other 400 millions having been provisioned separately). Assuming that the total coverage currently guaranteed is F 2,500 millions (600 by EDF and the rest by the State or a pool of States), the theoretical premium would be 525 millions francs per year, or about 10 millions francs per year and per reactor.

The R & D expenses used include safety expenses, research on cycle back-end activities, radiation shielding, research on the reactors cycles, research on new fuels.

The following table presents variations assumed in the different scenarios for expenses that are not paid by manufacturers or the energy producer.

Variation of nuclear research expenses in the different scenarios

Billions francs/year	2000-2010	2010-2020	2020-2030	2030-2040	2040-2050
H1, B4	3.4	2.7	2.2	2	1.7
B4 30	3	2.2	1.4	1	1
EPR scenarios	3.55	2.9	2.7	2.7	2.7
EPR + RHR 1	3.55	3.4	2.9	2.9	2.9
EPR + RHR 2	3.6	3.4	3.2	3.2	3.2

3.2. Options using fossil fuels and renewable energies

The main characteristics of the selected options are shown in the following table.

Investment and operating costs for the main fossil fuels and renewable energy options

	2000		2020		2030		2040		2050	
Invest. FF/installed kWe										
Combustion turbine (oil-fired)	2 130		2 344		2 290		2 235		2 180	
650 MWe CCG base	3 950		3 335		3 160		2 940		2 835	
650 MWe CCG semi-base	3 750		3 165		3 000		2 790		2 690	
Own prod - co-generation	5 050		3 585		3 175		2 945		2 780	
Gas engines	6 120		4 080		3 570		3 264		3 060	
Combustion turbine (gas-fired)	4 220		3 090		2 780		2 625		2 500	
600 kWe wind-powered generator	9 800		7 840		6 270		5 490		4 700	
1 500 kWe wind-powered generator	7 060		5 600		4 480		3 920		3 360	
Fuel cell	Ns		3 980		3 365		2 855		2 450	
Operating costs	**CF/ kWh**	**F/ kWe**	**CF/ kWh**	**F/ kWe**	**CF/ kWh**	**F/ kWe**	**CF/ kWh**	**F/ kWe**	**CF/ kWh**	**F/ kWe**
Coal (CPTF, 600 MWe)	1.45	210	1.45	210	1.45	210	1.45	210	1.45	210
Combustion turbine (oil-fired)	1.2	35	1.2	35	1.2	35	1.2	35	1.2	35
650 MWe CCG base	1.2	65	1.2	65	1.2	65	1.2	65	1.2	65
650 MWe CCG semi-base	1.2	65	1.2	65	1.2	65	1.2	65	1.2	65
Own prod - co-generation	0.01	105	0.1	105	0.1	105	0.1	105	0.1	105
Gas engines	0.01	120	0.01	120	0.01	120	0.01	120	0.01	120
Combustion turbine (gas-fired)	0.01	85	0.1	85	0.1	85	0.1	85	0.1	85
600 kWe wind-powered generator	0	440	0	440	0	440	0	440	0	440
1 500 kWe wind-powered generator	0	315	0	315	0	315	0	315	0	315
Fuel cell	0.013	120	0.013	120	0.013	120	0.013	120	0.013	120

Investment costs vary between 2 000 to more than 7 000 francs per kWe depending on the system. Structures and values of the operating costs (apart from fuel) of the various systems are also very different and vary from 35 to 440 francs per kWe for fixed costs and 0.01 to 1.5 centime for variable costs.

Note that the precision of the information used (both for technical efficiency and for investment and operations) is fairly dependent on the technology. Thus, the proposed estimates are more reliable for combustion turbines, gas turbines and co-generation than for wind-powered generators and particularly fuel cells. But the influence of these inaccuracies is low to the extent that these technologies only play a minor differential role in the total balances of the different scenarios over the period 2000-2050.

3.3. Gas and electricity networks

The various described scenarios assume very different requirements to reinforce gas and/or electricity networks, and the investments and operating costs for this work must be included. The report produced by the « Future technological prospects for non-nuclear energy sources » group contains two specific notes on these questions.

3.3.1. The electricity network

Considering electricity transmission and distribution, the various scenarios can be broken down into three categories differentiated by different network developments :

- The first assumes a high network development trajectory (H1, H2, H3) with 795 TWh to be transmitted and distributed in 2050, including 695 through the main transmission network ;

- the second assumes a median network development trajectory (B2, B3) with 592 TWh to be transmitted and distributed in 2050, including 492 through the main transmission network ;

- the third assumes a low trajectory (B4, B4 30) with 590 TWh to be transmitted and distributed in 2050, including 445 through the main transmission network.

The main assumptions used to estimate renewal and extension costs for main transmission networks (400 kV and 225 kV), regional distribution networks (90 kV and 63 kV) and distribution networks (400 V to 20 kV) are as follows :

- despite the fact that gas turbines are more flexible than nuclear reactors (higher efficiency, less cooling requirements, fewer safety requirements), it is considered that there was no decisive argument for using different transmission network costs depending on the nature of the centralised power stations used (600 MWe gas power stations or nuclear power stations) ;

- in 2050, in all scenarios, 100 TWh will be produced in industries other than the power industry and in tertiary industries connected to the high voltage network. It is estimated that part (50 TWh) of this energy will be consumed near the production site on which it is generated, and that 50 TWh will be carried on the regional transmission and distribution network ;

- in the B4 scenarios in which 55 TWh is produced in a very decentralised manner in the residential sector, the same distribution rule is maintained assuming that half of this electricity will be consumed close to the production site on which it is generated and that the other half (27.5 TWh) will be carried on the network to take account of standby needs for these installations ;

- it is assumed that all transmission and distribution installations will have to be replaced during the 2000-2050 period due to technical progress and for town planning constraints, although the life of the structures will probably be greater than 50 years.

Thus, the timing of investments necessary for extension, renewal and upkeep of the different types of networks have been described for each of the trajectories, based on available information [1].

The following is a summary in the form of the corresponding accumulated capital investment expenses for the period 2000-2050.

Investments for electrical networks

Investments in billions francs (2000-2050)	**High trajectory**	**Low trajectory**	
	H1, H2, H3	**B2, B3**	**B4, B4 30**
Main transmission	79	61	55
Regional distribution	149	119	109
Distribution	525	419	390
Total	753	599	554

(1) Champsaur report, EDF communications.

Network operating costs were determined assuming [1] that costs related to low voltage transmission and distribution networks will remain constant regardless of the electricity demand.

3.3.2. The natural gas network

It is proposed to use the technical analysis of the characteristics of supply installations (and particularly needs for gas storage installations), information supplied by several gas companies (GDF, Elf and Suez-Lyonnaise) and Digec analyses, as a basis for describing gas network investments in the form of the sum of two terms, one related to the characteristics of the site with storage needs, and the other to the storage itself.

Term related to the site :

- special supply sites for very high power equipment : 25 MF/TWh [2] ;
- industrial sites with medium power equipment (5 to 100 MWe) : 45 MF/TWh ;
- residential sites with equipment smaller than 5 MWe : 115 MF/TWh.

Term related to storage :

- on demand between 7,000 and 8,000 hours : F 30 million/TWh ;
- on demand for 4,000 hours basically in the winter : F 150 million/TWh ;
- on demand for 2,500 hours basically in the winter : F 225 million/TWh ;
- on demand for 1,000 hours basically in the winter : F 310 million/TWh.

Finally, network-operating costs were considered as being proportional to investments (3.4 % of investment).

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(1) We were unable to collect sufficient informations to calculate transmission and distribution costs separated into two parts, one fixed and the other proportional to the quantities distributed. It is very probable that fixed operating costs are largely predominant, but note that considering the importance of operating costs of distribution networks in the final cost of distributed electricity, assignment of even a modest variable part would cause a significant extra operating cost in the high trajectories (H1,H2, H3) compared with the low trajectories.
(2) We chose to express terms related to the site or storage in millions of Francs per TWh of electricity.

The main results are shown in the following table for each type of installation :

Natural gas network investment and operating costs

Millions of F/TWh	Capital investment		Operation
	Transport	Ultimate disposal	
Fuel + Combustion turbine	45	350	13.5
650 MWe CCG base	25	36	2
650 MWe CCG semi-base	35	100	4.6
Own prod. - co-generation	medium	medium	medium
Gas engine	115	150	-
Gas combustion turbine	-	-	-
Gas fuel cell	-	-	-

4. Comparison between accumulated economic flows and costs associated with the different scenarios

The comparison is made for the following scenarios chosen among the various possible scenarios :

- scenario H1, with reprocessing continued until 2020 and use of MOX in existing PWR reactors (28 units), without any renewal of PWR reactors at the end of their lives (average 45 years life) ;
- scenario H2, with continued reprocessing and EPR reactors introduced to replace PWR reactors at the end of their lives ; comments will be made on a variant using APA fuels ;
- scenario H3, with continued reprocessing and introduction of EPR reactors to replace PWR reactors at the end of their lives ;
- scenario B2 with continued reprocessing until the end of the life of existing PWR reactors and introduction of EPR reactors starting from 2030-2035. Comments will be made on a variant in which RHR 1 reactors are introduced at the same time burning firstly plutonium derived from MOX irradiated in PWRs, and then uranium enriched to 20 % after the PWRs have been shut down ;
- scenario B3, with continued reprocessing and introduction of EPR reactors to replace PWR reactors at the end of their lives ;

- scenario B4, with reprocessing stopped in 2010 without renewal of nuclear power stations at the end of the life of existing nuclear stations (average 45 years life) ;
- scenario B4 30, in which reprocessing is stopped in 2010 without any renewal of the nuclear power stations at the end of the life of existing nuclear stations limited to 30 years.

In a first step, we considered the comparison of accumulated costs of strategies developed in the different scenarios, between 2000 and 2050. Therefore, we study the situation in 2050 and summarise all expenses incurred since 2000 to build, maintain and operate the electrical systems proposed in the scenarios.

The tables used also present histories of inevitable expenses that will have to be made beyond 2050 (dismantling of nuclear installations, interim storage and ultimate disposal of nuclear waste and irradiated fuel, etc.). These expenses will have to be paid after 2050, and will be included at the end of the chapter using a discounted calculation.

Cash flows and accumulated expenses are sorted into three separate main headings :

- *investments* (electrical capacities, gas pipes, reinforcement of electrical networks, nuclear fuel manufacturing capacity, reprocessing plants, interim storage and ultimate disposal capacities, etc.) ;
- *fuel costs* (purchase at frontiers or from national producers of coal, natural gas, fuel oil or nuclear fuel) ;
- *operating costs* other than fuel costs (maintenance, operation, etc.).

Finally, an « *R & D* » section was considered, the importance of which depends mainly on the importance assigned to the development of nuclear in the scenarios.

4.1. Investments

The first observation is a large difference in accumulated investments between high and low electricity demand scenarios. The accumulated investment for high electricity demand scenarios is F 1,964 billion compared with F 1 521 billions for low electricity demand scenarios, which is 29 % higher (on average of the order of F 8.9 billions per year).

In high and low demand scenarios, investments are higher when the proportion of nuclear power stations out of the total is higher : for example, there is a difference of F 567 billions between scenario H1 in which there is no renewal of power stations after a life of 45 years and scenario H3 which includes nuclear power stations with a total capacity of 85 GWe in 2050 (+ 34 %).

Similarly, the investment difference between scenario B4 with no renewal of nuclear power stations and scenario B3 (47 GWe in 2050) is equal to F 323 billions, equal to 23 %.

We will go even further in the comparison between the various scenarios by examining the structure of investments in each scenario, making a distinction between the investments in terms of production capacity (power stations), investments in gas and electricity infrastructures (networks), and investments for the nuclear fuel cycle.

The following table compares the different accumulated investment cost structures for the different scenarios.

Accumulated investment costs (2000-2050)

Investments billions Francs	**H1**	**H2**	**H3**	**B2**	**B3**	**B4**	**B4 30**
Power stations	769	1 077	1 323	887	977	682	647
Gas network	53	51	22	36	25	47	47
Electrical network	754	754	754	599	599	560	554
Fuel cycle	89	114	133	105	114	103	103
Total	1 665	1 996	2 232	1 627	1 715	1 392	1 351

The two largest items in all scenarios are investments for power stations and reinforcement of the electricity transmission network. The next largest item is the fuel cycle, and then reinforcement of the gas network for which the amount is marginal.

It may be interesting to examine the comparison between scenarios based on nuclear and scenarios based on gas in more detail, by accumulating firstly « nuclear power stations + fuel cycle » investments for the nuclear option, and secondly « gas power stations + gas network » investments for the gas option.

Gas and nuclear investments (2000-2050)

Investments in billions Francs	H1	H2	H3	B2	B3	B4	B4 30
Nuclear power stations	293	700	1 089	609	736	277	140
Nuclear cycle	89	114	133	105	114	103	103
Total nuclear	**382**	**814**	**1 222**	**714**	**850**	**380**	**243**
Gas power stations	285	133	44	87	51	147	275
Gas network	53	51	22	36	25	47	47
Total gas	**338**	**184**	**66**	**123**	**76**	**194**	**322**

This comparison illustrates the large proportion of nuclear investments to be made compared with investments for the construction of gas power stations in all scenarios, even when existing power stations are not renewed at the end of their lives. The only scenario in which nuclear investments are lower than gas investments over the 2000-2050 period is scenario B4 30.

The following table compares the total amount of predicted investments that will become necessary after 2050 in all cases for the different scenarios. In order to take into account the fact that power stations that will be existing in 2050 will have a wide variety of structures and therefore lives, the total accumulated quantities of electricity [1] that can be expected from these power stations beyond 2050 have been shown adjacent to these investments.

Total amount of unavoidable expenses to be committed and accumulated producible electricity [2] for the different scenarios beyond 2050

Billions Francs after 2050	Total expenses	Total elec. (TWh)	including nuclear
H1	14	15 100	0
H2	140	35 500	16 700
H3	251	37 960	24 690
B2	102	24 680	12 030
B3	102	25 300	15 250
B4	14	17 200	0
B4 30	0	20 120	0

(1) In choosing the period 2000-2050, we include nuclear and gas investments that will generate electricity well beyond 2050, particularly for nuclear.

(2) The « producible » electricity is defined as the maximum possible accumulated quantity of electricity for these scenarios beyond 2050, using facilities that will be existing in 2050.

4.2. Operation

This includes all costs committed to manage and maintain production tools, fuel procurement networks and electricity supply networks, at the same time.

Total operating costs over the 2000-2050 period represent almost 75 % of accumulated investment costs. As in the previous case, the first thing that is observed is the large differences between average total operating costs for the high and low electricity demand scenarios, namely F 1,390 billions on average for H (high) scenarios compared with 1,160 for B (low) scenarios, with a difference of the order of 20 %.

The following table shows the structure of these costs in the different scenarios.

Structure of accumulated operating costs for the different scenarios (2000-2050)

Operation (billions of francs)	H1	H2	H3	B2	B3	B4	B4 30
Power stations	1 103	1 181	1 302	1 083	1 124	1 035	781
including nuclear	*776*	*935*	*1 148*	*875*	*953*	*769*	*361*
CCG	*208*	*123*	*34*	*73*	*39*	*108*	*240*
Others	*120*	*123*	*120*	*136*	*132*	*158*	*180*
Fuel cycle	133	201	243	183	198	129	103
Total	**1 236**	**1 382**	**1 545**	**1 266**	**1 322**	**1 164**	**884**
including nuclear	*909*	*1 136*	*1 391*	*1 058*	*1 151*	*898*	*464*

This table shows the magnitude of nuclear in the accumulated operating costs for the scenarios since the operating costs related to nuclear reactors account for 73 % to more than 90 % of all operating costs in all scenarios, except for scenario B4 30 where they still represent 53 % of all accumulated operating costs [1].

Faced with the magnitude of nuclear power station operating costs, we considered the consequences if EPR power stations do not perform as well as expected. This assumption consists of using a fixed operating cost of

(1) In this respect, we have to note that nuclear power stations are not used to their maximum capacity in some of the envisaged scenarios, and particularly in scenario H3. Therefore, it would be possible to improve the overall operating balance for these scenario by adopting a policy to export unused potential producible electricity.

F 340/kWe for the reactors (similar to the cost used for existing PWR reactors for the same period). This corresponds to an operating cost of 5 centimes per kWh for the use of EPR power stations as the base supply.

The following table is helpful for analysing the consequences.

Accumulated operating costs for nuclear power stations over the 2000-2050 period

Billions of francs	Nuclear power station operating cost		Difference
	Median assumption	High assumption	
H1	1 236	1 236	0
H2	1 382	1 432	50
H3	1 545	1 665	120
B2	1 266	1 299	33
B3	1 322	1 381	59
B4	1 164	1 164	0
B4 30	884	884	0

With this high assumption corresponding to a higher operating cost for EPR reactors, the total operating costs are unchanged for H1, B4 and B4 30, and for H2 increase by F 50 billions (3.6 %) compared with the median assumption for operating costs, and increase by F 120 billions (7.8 %) for H3, F 33 billions (2.6 %) for B2 and F 59 billions (4.5 %) for B3. Therefore, the magnitude of these extra costs clearly shows the importance of strict control over operating costs for power stations and the fuel cycle.

4.3. Fuels

Accumulated expenses for the purchase of fuels depend very strongly on assumptions about changes to the costs of fossil fuels, as shown in the following table produced for the three assumptions described at the beginning of this chapter.

Scenarios with a high proportion of nuclear are naturally the least sensitive to changes in fossil fuel costs. For example, in H1, although fuel costs are of the same order as investment costs for the « constant » scenario, they are 1.7 times higher than investment costs for the « tension » scenario. On the other hand, in H3, the sensitivity to a variation of fuel costs is much smaller since these costs only represent 35 % of investment costs.

The following table shows the structure of these costs for each option, for each assumption about the variation of fossil fuel prices.

Accumulated fuel costs per option for the different assumptions about variations in the fossil fuel price (2000-2050)

Fuel cost (billions FF)	**H1**	**H2**	**H3**	**B2**	**B3**	**B4**	**B4 30**
Constant							
Coal	36	36	36	9	9	9	30
Gas	1 635	1 184	659	917	728	1 266	2 037
Nuclear	297	361	447	323	355	274	163
Total	**1 968**	**1 581**	**1 142**	**1 249**	**1 092**	**1 549**	**2 230**
Break in conditions							
Coal	36	36	36	9	9	9	30
Gas	2 116	1 495	813	1 151	902	1 622	2 546
Nuclear	297	361	447	323	355	274	163
Total	**2 449**	**1 892**	**1 296**	**1 483**	**1 266**	**1 905**	**2 739**
Tension							
Coal	36	36	36	9	9	9	30
Gas	2 788	1 960	1 062	1 508	1 179	2 132	3 344
Nuclear	297	361	447	323	355	274	163
Total	**3 121**	**2 357**	**1 545**	**1 840**	**1 543**	**2 415**	**3 537**

In almost all cases (except for scenarios H3 and B3 with fossil fuel prices assumed to be constant), accumulated costs for nuclear fuels are low compared with accumulated costs of gas purchases.

4.4. Research and development

Most R & D expenses made during the period are integrated into the investment and operating costs of the different options. However, some research and development expenses are not included in these costs for nuclear power. These costs vary between F 86 billions and F 146 billions depending on the scenario as shown in the following table.

Accumulated R & D expenses not included in operations or investment

Billions FF	R & D
H1	120
H2	146
H3	146
B2	146
B3	146
B4	120
B3 30	86

These costs vary between 2 and 2.4 % of all accumulated costs (investment, operation, fuels, R & D) over the period, depending on the case.

4.5. Summary of accumulated expenses from 2000 to 2050

The following tables show the overall results, giving accumulated total costs and the cost distribution for each assumption about the variation in fossil fuel costs.

Accumulated total expenses for each scenario for different assumptions about variations in fossil fuel prices (2000-2050)

Billions FF	**H1**	**H2**	**H3**	**B2**	**B3**	**B4**	**B4 30**
Constant							
Capital investment	1 665	1 996	2 232	1 627	1 715	1 392	1 351
Operation	1 236	1 382	1 545	1 266	1 322	1 164	884
Fuel	1 968	1 581	1 142	1 249	1 092	1 549	2 230
R & D	120	146	146	146	146	120	86
Total	**4 989**	**5 105**	**5 065**	**4 288**	**4 275**	**4 225**	**4 551**
Break in conditions							
Capital investment	1 665	1 996	2 232	1 627	1 715	1 392	1 351
Operation	1 236	1 382	1 545	1 266	1 322	1 164	884
Fuel	2 449	1 892	1 296	1 483	1 266	1 905	2 739
R & D	120	146	146	146	146	120	86
Total	**5 470**	**5 416**	**5 219**	**4 522**	**4 449**	**4 581**	**5 060**
Tension							
Capital investment	1 665	1 996	2 232	1 627	1 715	1 392	1 351
Operation	1 236	1 382	1 545	1 266	1 322	1 164	884
Fuel	3 121	2 357	1 545	1 840	1 543	2 415	3 537
R & D	120	146	146	146	146	120	86
Total	**6 142**	**5 881**	**5 468**	**4 879**	**4 726**	**5 091**	**5 858**

We can start by comparing high and low electricity demand scenarios.

In the « constant price » assumption, the average cost for low electricity demand scenarios shows a total saving of F 718 billions over the period compared with the average cost of high electricity demand scenarios (an average of 14.5 billions per year). The extra cost of high scenarios is equal to 16 %.

This difference in favour of low scenarios remains practically constant regardless of the cost of fuel (F 715 billions in the « break in conditions » assumption and F 691 billions in the « tension » assumption).

Therefore, in all cases there is a large latitude, of the order of F 14 billions per year between now and 2050, for developing the necessary public electricity control policies.

A more detailed analysis for each assumed variation in the cost of fossil fuels shows up the following points.

A - « Constant » fuel costs assumption

In the high and low electricity demand scenarios, the accumulated costs for scenarios in which nuclear is not renewed at the end of the life of existing plants (45 years) are less than accumulated costs for scenarios that assume that nuclear power is renewed (from F 63 to 116 billions depending on electricity demand). Scenario B4 30 by which nuclear is phased out at 30 years is F 326 billions more expensive than scenario B4, F 276 billions more expensive than B3, and F 263 billions more expensive than scenario B2 [1], but is significantly less expensive (by about F 500 billions) than all high electricity demand scenarios.

B - « Break in conditions » gas and oil prices assumption

The accumulated costs of scenarios H1 and H2 are very similar for this assumption. Scenario H3 becomes even more economic than H1 and H2 by 200 to 250 billions francs. For the B (low) scenarios, scenarios B2 and B3 are 60 to 130 billions francs less expensive than B4. The anticipated phasing out of nuclear (B4 30) becomes significantly more expensive under these conditions, with 10 % extra cost accumulated over the period compared with B4 (F 480 billions), but are less expensive than each of the H scenarios.

C - « Tension » fossil fuel prices assumption

With these assumptions for a high electricity demand, scenario H3 has the lowest accumulated cost, followed by H2 (+ 7.5 %) and H1 (+12.3 %). The same is true for scenario B3 that is the least expensive, followed by B2

(1) This scenario (unlike the others) allows for the construction of electricity generating capacities necessary for the export of electricity until 2020 defined in scenario S3 in the « 2010-2020 Energy report », combined cycle capacity that would probably not be built specifically for export in this case.

(+ 3.2 %) and B4 (+ 7.7 %). Scenario B4 30 is significantly more expensive under these new fossil price conditions (15 % more than B4).

In conclusion, it can be noted that the accumulated cost of scenario B4 30 during the 2000-2050 period is always higher than scenario B4, regardless of the assumption about the change in fuel prices ; if fuel prices are constant, scenarios H1 and B4 in which nuclear power stations are not renewed are the least expensive ; and if prices are competitive, then scenarios H3 and B3 in which a large proportion of the nuclear power stations are replaced are the least expensive. However, these conclusions must be considered taking account of the fact that they are based on undiscounted data.

Two nuclear variants have been estimated, one with a new generation of RHR 1 reactors with scenario B2, and the other using a new fuel, APA, with scenario H2.

APA variant with scenario H2

We have attempted to estimate the accumulated costs of this option using the following main assumptions :

- it is assumed that there are no extra research costs outside the one included in the EPR option, for which fuel research costs have already been included (APA + MOX Th + cycle) equal to F 0.2 billion per year [1] ;
- a multiple fuel reprocessing plant is planned to be built around 2030-2035 with a capacity of 900 tonnes/year and a fuel disassembly workshop with an investment cost estimated at F 4 billions ;
  - the cost of APA fuel is estimated at F 6,000/kg, the same as for MOX ;
  - power stations operating costs are assumed to be the same as for EPR power stations ;
- there are no plans to build any interim storage before 2075 ; this assumption is not the same as the one for EPR system for which several surface interim storages need to be built by 2050.

The structure of accumulated costs for scenario H2 using APA fuel and for the same scenario using EPR reactors is as follows.

(1) Source : « La prospective technologique des filières nucléaires - Future technological prospects for nuclear energy » report.

	Investment	Fuel	Others	R & D	Total
H2 EPR	1 995	1 580	1 382	146	5 103
H2-APA	2 004	1 572	1 350	146	5 072

RHR 1 variant for scenario B2

Accumulated costs for this option are estimated based on the following main assumptions :

- research costs during the 2000 to 2050 period equal to a F 10 billions more than for the EPR option (which are F 156 billions) ;
- construction of an industrial prototype in another country, therefore at no cost for France ;
- investment cost F 12,675 per kWe for the first production unit, dropping to F 9,750/kWe starting from the fourth unit ;
- fuel cost equal to F 8,000/kg ;
- power station operating cost equal to F 340/kWe + 0.45 centime/kWh.

Under these conditions, the accumulated costs for scenarios B2 RHR 1 and B2 EPR are as follows.

	Capital investment	Fuel	Others	R & D	Total
B2 EPR	1 628	1 249	1 266	146	4 287
B2-RHR 1	1 653	1 214	1 246	157	4 269

In both variants, accumulated costs are very similar to the equivalent scenarios using an EPR power station. However, these figures should be used with caution, since the proposed financial estimates are not based on any field experience. Furthermore, neither of these two options will be possible unless research and development programs that have not yet been completed are successful, and industrial structures that do not yet exist are built.

However, material balances for these scenarios are significantly better than for their EPR equivalent, as can be seen in the following table.

2000-2050	
Transuranic elements	**Tonnes**
H2 EPR MOX	473
H2 EPR APA	221
B2 EPR	411
B2 RHR 1	115

5. The time structure of expenses corresponding to the different scenarios

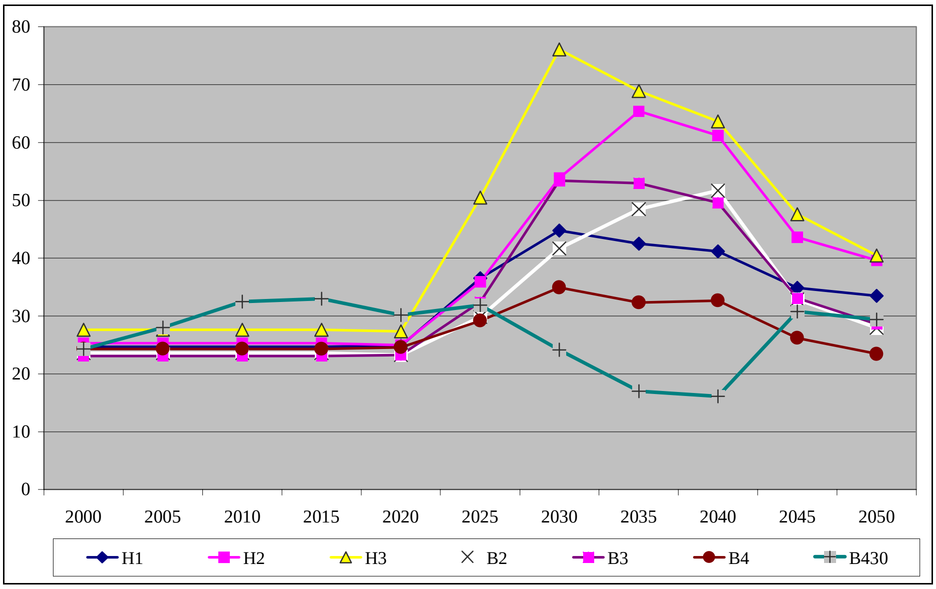
The various scenarios differ in their global cost, and also in the time at which the expenses are made. We have attempted to present these expenses in steps of five years between 2000 and 2050.

5.1. Chronology of expenses

Investments

For high electricity demand scenarios, the capital investment calendar shows that the necessary investment for scenarios in which existing nuclear power stations are replaced by new nuclear power stations is greater than scenarios in which nuclear power stations are not renewed, at all times. The same is true for low electricity demand scenarios (except for the 2000-2020 period in the case of B4 30). Furthermore, in each period, investments necessary for B (low) scenarios are always lower than for H (high) scenarios, except for scenario H1 (without renewal of nuclear power stations) for which annual investments are lower than for B2 and B3 between 2030 and 2050.

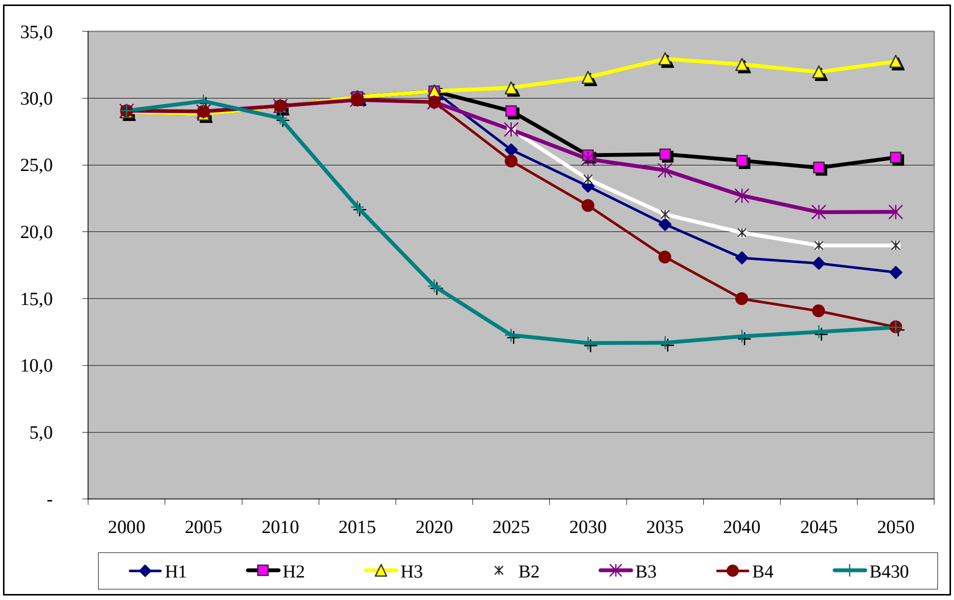
Capital investment calendar (billions FF)



Operating costs

Operating cost calendars also vary quite differently. The curves diverge increasingly with time. Costs for scenarios H2 and H3 are highest at all times during the period. Costs for the B4 30 and B4 scenarios are lowest at all times.

Operating costs calendar (billions of Francs)

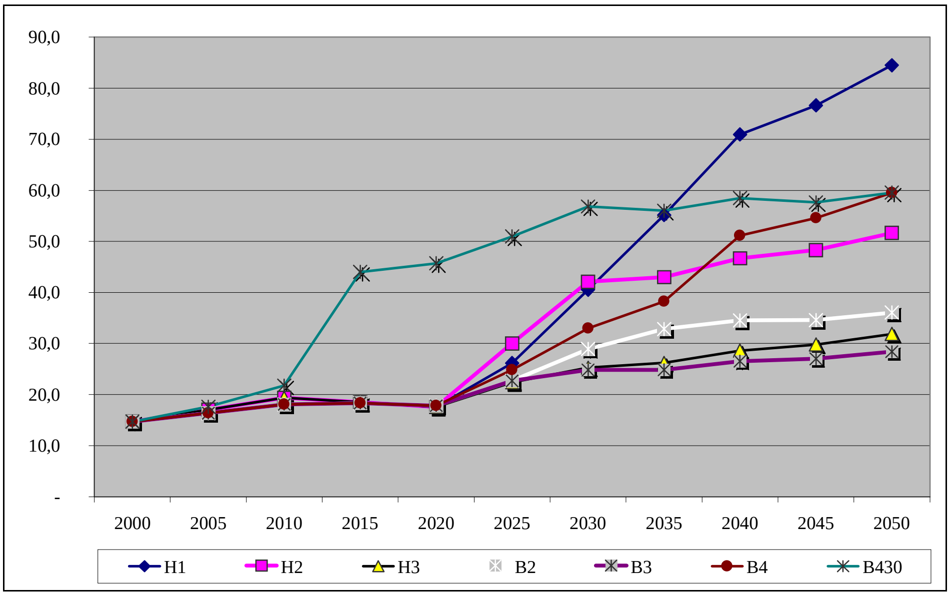


Fuel costs

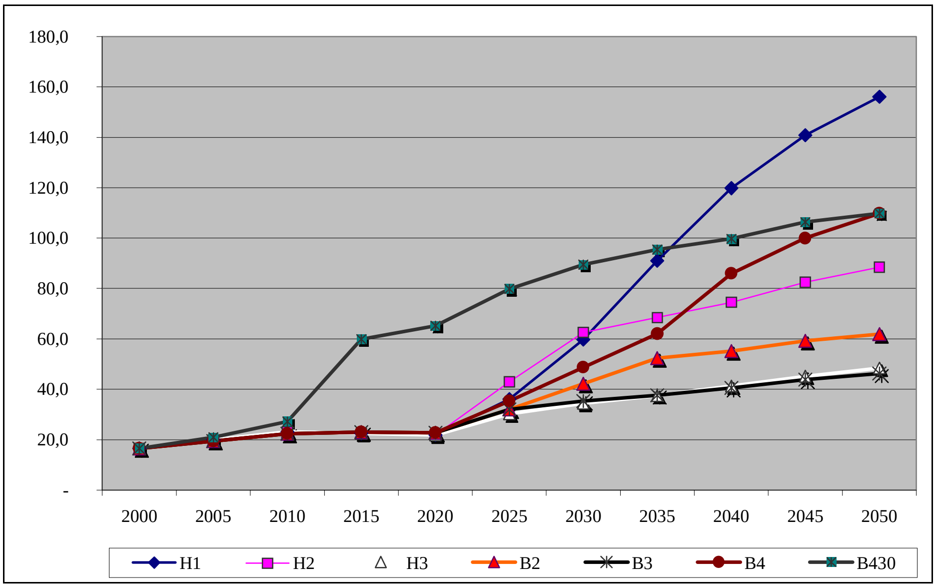
We chose to illustrate the two extreme cases, the « constant » assumption and the « tension » assumption. The shape of the fuel cost curves is the same in both cases, and there is a continuingly increasing difference between scenarios that use nuclear power and scenarios in which nuclear power is phased out.

At the end of the period, fuel costs are almost three times higher for scenario H1 than for scenarios H3 and B3. The difference is as high as a factor of 3.3 for the tension fossil fuel price assumption.

Fuel costs calendar (« constant » assumption) (billions FF)



Fuel costs calendar (« tension » assumption) (billions FF)

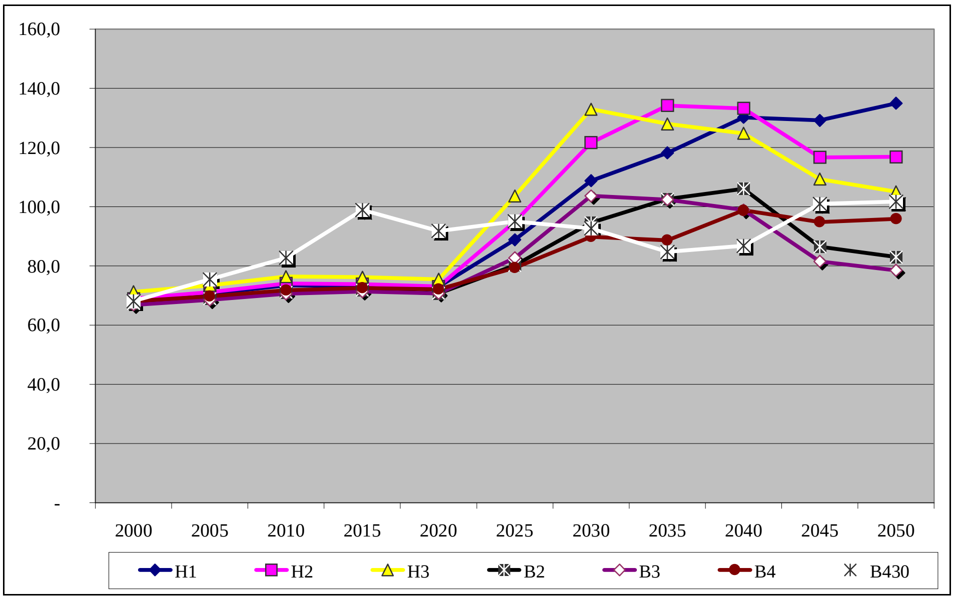


Total costs

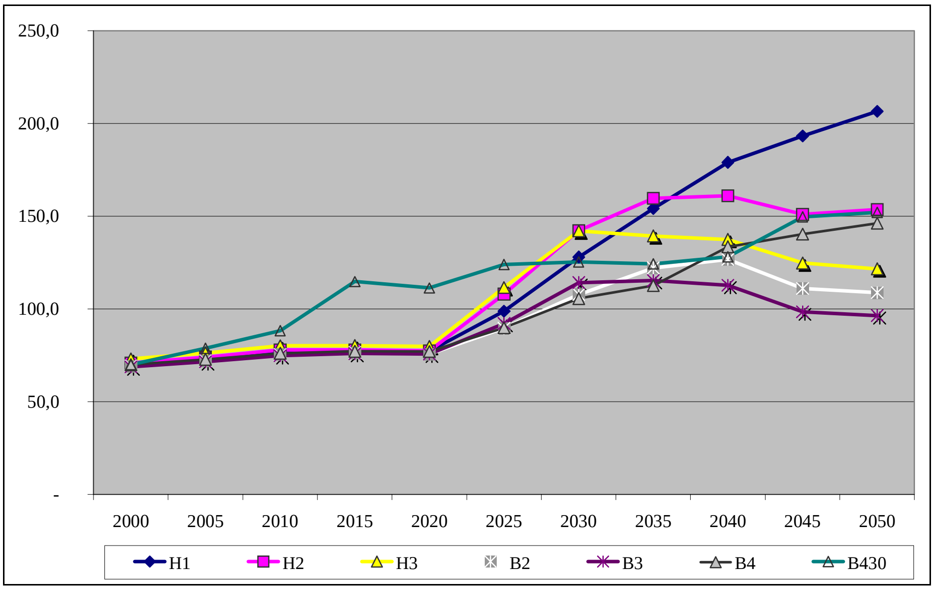
The following graphs shows the calendars for the total costs of scenarios for the two extreme assumptions about variations in the costs of fossil fuels, namely the constant assumption and the tension assumption.

In both assumptions, annual costs for each scenario increase significantly after 2020, and do not stabilise or drop until after 2040. This is the result of investments to be made during the 2020-2040 period to renew the electrical power stations built between 1980 and 2000.

Total costs calendar (« constant » assumption) (billions FF)



Total costs calendar (« tension » assumption) (billions FF)



A chronological analysis of accumulated costs during each period shows that accumulated costs for the three H scenarios are always greater than accumulated costs for the B scenarios, except for scenario B4 30 for which all expenses in the first 2000-2030 period exceed the accumulated costs for the other scenarios.

5.2. Discounted balances

Economic calculations frequently take account of choices made at different times by using one or several discount rates to reflect a preference for the present over the future.

However, there are many problems in choosing a discount rate. Some authors prefer to use the real rate of interest on the financial market because it fairly accurately translates the degree of competitiveness between supply and demand for savings at different times. But the rate of interest is not meaningful beyond a certain length of time. Other authors recommend that a discount rate decreasing with time should be used whenever considering very long periods for choices with large uncertainties. Others prefer a very low discount rate whenever the management of natural resources is involved.

For a long time, the Franch Planning Office has recommended a rate of the order of 8 % for 5-year arbitrations. For a period of 50 years [1], we thought it reasonable to use a two-part rate ; firstly an intermediate rate equal to 6 %, between the recommended 8 % and the financial market rate (4 %) during the first period from 2000 to 2030 ; and a significantly lower rate (3 %) for the following period, considering the wealth effect from which future generations will benefit.

These are the bases on which we prepared the discounted balances ; they include everything related to costs (investments, operation, fuel, R & D) until 2050, and also costs related to dismantling and interim storage of waste until the end of the life of reactors existing at the moment. The discounted extra cost for dismantling and interim storage of waste is very low since it is applicable to costs that are always very much less than 5 % of the total, and furthermore will be incurred after 2050 so that their influence is very much reduced due to discounting. These additional discounted costs are different for the different scenarios, for example varying from F 10 billions for B4 30 to F 50 billions for H3.

Discounted balances

Discounted total cost (billions FF)	Constant	Break in conditions	Tension
H1	1 906	2 042	2 239
H2	1 957	2 048	2 188
H3	2 051	2 099	2 183
B2	1 710	1 781	1 895
B3	1 714	1 768	1 861
B4	1 689	1 792	1 947
B4 30	1 739	1 890	2 136

Discount rate : 6 % from 2000 to 2030, then 3 %

Comparison between high and low electricity demand scenarios

Firstly, it can be seen that discounting does not eliminate the significant difference in accumulated costs between high and low electricity demand scenarios, calculated at zero discount. Based on assumptions for the variation of fuel costs, the difference between the average of high and low scenarios varies from F 267 to 312 billions, corresponding to an extra cost of 15 % for constant prices and 16 % for competitive supply, for high electricity demand scenarios.

(1) See an analysis of discounting in the appendix.

It is also useful to compare unit costs of electricity generated in the different scenarios by comparing the total discounted cost of each scenario with the total discounted number of kWh produced. This unit cost corresponds to the implicit price at which each kWh would have to be sold if it was required to recover the discounted costs paid in the form of discounted income. We made this calculation for the 2020-2050 [1] period, since the power stations are all the same in all scenarios until 2020 (except for B4 30). The results are summarised in the following table.

Discounted average cost per kWh during the 2020-2050 period in the different scenarios

Centimes/kWh	Constant	Break in conditions	Tension
H1	17.2	19.0	22.0
H2	18.3	19.2	21.6
H3	19.5	20.1	21.1
B2	17.8	18.8	20.8
B3	18.0	18.8	20.2
B4	16.8	18.6	21.2
B4 30	17.7	20.5	24.4

The discounted average unit costs of electricity for high electricity demand scenarios are again significantly higher than estimated costs for low demand scenarios with the same structure of production power stations.

For example, there is a saving of 1.5 to 0.8 centimes (7 % to 5 %) on the production of each kWh between scenarios B3 and H3 depending on the assumed changes in fuel costs ; there are corresponding savings of 0.4 to 0.8 centimes per kWh between scenarios B2 and H2, and finally 0.1 to 0.8 centimes between scenarios B4 and H1. The costs per kWh of the scenario in which nuclear is phased out after the end of a 30-year life of each power stations are always significantly higher than the costs per kWh of the scenario in which the power stations are kept in operation for a life of 45 years (B4).

The above two tables once again illustrate the advantage of electricity control policies, since this type of policy can achieve major savings for the entire electricity system and savings in the unit cost of electricity generated. This is

(1) The same information is given later for the 2000 –2050 period.

true provided that the cost of these policies remains lower than the advantage [1] equal to F 267 to 312 billions calculated on discounted balances [2].

Comparison of discounted costs as a function of fossil fuel cost assumptions.

A – « Constant » assumption

If fuel prices remain constant over the period, scenario B4 (low electricity consumption with nuclear power replaced by combined cycles with gas) would be the least expensive with discounted costs equal to F 1 190 billions. Scenarios B2 and B3 are equivalent and their cost is 2 % higher than B4. However, the costs for H (high) scenarios are significantly more than for B4 (13 % for H1, 16 % for H2 and 22 % for H3).

The accumulated saving of electricity consumed between 2000 and 2050 for low consumption scenarios compared with high consumption scenarios is 1,459 TWh, and the discounted cost difference between these same scenarios is equal to F 267 billions. Therefore, this represents a saving of 18.3 centimes per kWh saved whereas the discounted average cost per kWh in scenario B4 over the 2000 to 2050 period is 16.1 centimes, as can be seen in the following tables showing the discounted average cost per kWh during the 2000-2050 and 2020-2050 periods.

Discounted average cost per kWh

« Constant » assumption

Centimes/kWh	**2000-2050**	**2020-2050**
H1	15.9	17.2
H2	16.5	18.3
H3	17.1	19.5
B2	16.3	17.8
B3	16.3	18.0
B4	16.0	16.8
B4 30	16.4	17.7

(1) The maximum amount available for these electricity control operations is of the order of F 700 billions (at zero discount rate).

(2) It is difficult to estimate the cost of these public policies. It should include R & D costs, demonstration costs and the costs of setting various incentives (regulation, special tax facilities, possibly subsidies). At the moment, all public electricity control policies adopted by the Ademe and EDF cost less than F 50 millions per year. Therefore, even if these incentives are multiplied by 20, the total would still be negligible considering the amounts involved.

B – " Break in conditions" assumption

If "break in conditions" are applicable for gas prices and oil prices, the discounted costs for the three B (low) scenarios are very similar, with B3 having a very slight advantage over B2 (F 200 billions) and over B4 (F 17 billions). Among the high electricity demand scenarios, scenario H1 is less expensive than scenarios H2 and H3.

Discounted average costs per kWh calculated over the 2000-2050 period are 1 to 1.6 centime higher than the calculated discounted average costs for the constant prices assumption for scenarios in which nuclear is not replaced, and 0.4 to 0.8 centime for scenarios in which existing power stations are replaced by new nuclear plants.

Discounted average cost per kWh
« Break in conditions » assumption

Centimes/kWh	2000-2050	2020-2050
H1	17.2	19.2
H2	17.3	19.6
H3	17.5	20.2
B2	17.0	19.0
B3	16.8	18.9
B4	17.0	18.6
B4 30	17.9	20.4

C – « Tension » assumption

In the "tension" fossil fuel prices assumption, scenarios that allow for renewal of nuclear by nuclear have a cost advantage compared with scenarios in which nuclear is gradually phased out : thus discounted cost of scenario H3 is 68 billions francs (1 %) lower than the discounted cost of H1, and F 29 billions lower than scenario H2 ; the discounted costs of scenarios B3 and B4 are lower than the discounted costs of scenario B4 by F 83 and 39 billions respectively. The discounted cost of the variant B4 30 that assumes that nuclear power stations are shutdown after a life of 30 years is F 183 billions (9 %) more than the discounted cost of B4 that assumes a life of 45 years.

Discounted average cost per kWh
« Tension » assumption

1997 centimes/kWh	2000-2050	2020-2050
H1	18.8	22.0
H2	18.5	21.6
H3	18.2	21.1
B2	18.1	20.8
B3	17.7	20.2
B4	18.5	21.2
B4 30	20.3	24.4

5.3. Costs per kWh by option

Finally, we calculated the discounted average cost (excluding transport and distribution) per kWh for different options, particularly for nuclear power and combined cycles with natural gas used in the different scenarios.

The result of this calculation is given in the following tables for the 2000-2050 period and for the 2020-2050 period. The 2020-2050 period is particularly interesting, because here the contributions of these two options only start to differ in the different scenarios starting from 2020.

In the « constant » prices assumption, the discounted average cost of a nuclear kWh during the 2000-2050 period is always less than or equal to the corresponding cost for the combined cycle with natural gas (CCNG) option.

However the trend reverses for some scenarios during the 2020-2050 period, in other words starting from the moment at which an investment has to be made in either nuclear power stations or CCNGs.

Discounted average cost for different options
« Constant » assumption

Centimes/ kWh	CCG		Nuclear	
	2000-2050	2020-2050	2000-2050	2020-2050
H1	14.7	14	12.7	13.0
H2	16.1	14.5	14.1	16.1
H3	20.0	14.4	14.7	16.6
B2	16	16.4	14.5	16.5
B3	18.5	19.3	14.5	16.8
B4	14.6	14.5	13.8	14.6
B4 30	18.6	15.2	10.2	43.7 [1]

In the « Tension » assumption, the discounted average cost of nuclear compared with CCNG remains competitive in both periods in all scenarios.

Discounted average cost for different options
« Tension » assumption

Centimes/ kWh	CCG		Nuclear	
	2000-2050	2020-2050	2000-2050	2020-2050
H1	20.6	19.6	12.7	13.0
H2	22.4	20.4	14.1	16.1
H3	25.4	19.9	14.7	16.6
B2	22.6	22.4	14.5	16.6
B3	25.4	25.3	14.5	16.8
B4	20.5	20.1	13.8	14.6
B4 30	25.1	22.1	10.2	43.7

5.4. Sensitivity to choices of the discount rate

In order to test the sensitivity to the choice of the discount rate, we calculated discounted economic balances using the 8 % discount rate used for calculations of reference costs prepared by the DGEMP, and comparing the results with the results of the previous calculations made firstly with a zero rate and then with our central assumption with a 6 % rate during the first thirty years and then 3 %.

(1) The high figure of the discounted average cost for the nuclear system obtained in B4-30 is related to the two fold effect of very low nuclear energy production and high costs (dismantling of installations, interim storage, ultimate storage).

This sensitivity can be evaluated by looking at the following comparison tables prepared for the two extreme fossil fuel cost assumptions.

1 – « Constant » assumption

Increasing the discount rate tends to reduce cost differences between the scenarios. However, note that the discount rate does not change the cost hierarchy between scenarios. In particular, the discounted cost of scenario B4 is always the lowest. The performances of scenario B2 are the same as B4 for a discount rate of 8 %.

Constant			
Total cost billions of Francs	**0 %**	**6 % and 3 %**	**8 %**
H1	4 989	1 906	1 054
H2	5 105	1 957	1 076
H3	5 065	2 051	1 124
B2	4 288	1 710	997
B3	4 275	1 714	1 003
B4	4 225	1 689	997
B4 30	4 551	1 739	1 017

2 - « Tension » assumption

The order of the costs changes in high scenarios ; the cost of scenario H3 is lower than the cost of scenarios H1 or H2 for low discount rates, but becomes higher if the discount rate is 8 %. This is a direct consequence of the fact that H3 involves large investments earlier than other scenarios. The same difference occurs for B3, for which the discounted cost is the same as the discounted cost of B2 if the rate is 8 %.

Tension			
Total cost billions of Francs	**0 %**	**6 % and 3 %**	**8 %**
H1	6 142	2 253	1 144
H2	5 881	2 217	1 153
H3	5 468	2 188	1 180
B2	4 879	1 910	1 066
B3	4 726	1 866	1 065
B4	5 091	1 949	1 077
B4 30	5 858	2 132	1 163

In conclusion, it is found that the discount rate has a large influence on the absolute value of the total costs associated with each of the scenarios, but it has very little influence on the hierarchy of costs in the different scenarios.

5.5. Evaluation of existing power stations in 2050

In considering this question, it was decided to use the H3 and B3 scenarios as references, making maximum use of nuclear for each type of electricity demand (high and low). We evaluated the production cost of the same quantity of electricity in the other scenarios assuming that combined cycles with gas would be constructed.

This was used as a basis to recreate discounted additional costs to be spent (for capital investment, fuel and operation) to reach the same accumulated production as nuclear production observed in H3 and B3.

This is shown in the following table that contains discounted costs beyond 2050 necessary to produce electricity equivalent to the production potential of scenarios H3 and B3.

Discounted costs

GF	Constant	Tension
H1	62	102
H2	40	56
H3	30	35
B2	24	32
B3	19	22
B4	46	75
B4 30	46	76

Assuming constant fuel prices between 2000 and the end of the life of the power stations, the resulting discounted saving varies from 1.6 % for H3 compared with H1, to 1.5 % for B3 compared with B4.

For competitive prices, scenario H3 gives discounted savings of F 67 billions compared with H1 (3 %) and F 21 billions compared with H2 (1 %).

6. Estimate of some external factors

As we saw in chapter 4, the consequences of the various electricity consumption and production scenarios on CO_2 emissions and the accumulated amount of high activity nuclear materials with very long life are different. Even if the nature of these two « external factors » is not the same (CO_2 emissions are global in nature and are controlled by international reduction commitments, whereas nuclear waste is still covered by national laws), we decided to take them into account in order to compare the prices of scenarios which differ mainly by the relative importance assigned to nuclear and natural gas in future electricity power stations.

One way of taking these external factors into account is to assign a value to them to express the relative importance assigned to controlling the accumulated values of the different emissions or different wastes over the 2000-2050 period. This is the method that was selected internationally for emissions of greenhouse effect gases, since the Kyoto reduction commitments required that a value is defined for carbon.

In both cases, unit values to be adopted depend firstly on the relative importance that society decides to assign to the two problems mentioned. They also depend on the target reduction to be achieved for the accumulation of greenhouse effect gases, or the manner used to deal with the problem of nuclear waste. Therefore it is impossible to present precise values.

However, an idea can be obtained about how taking account of the problems at different levels will affect the economy of the scenarios.

For emissions of greenhouse effect gases, the literature contains a wide range of figures for the value of carbon, varying from 10 dollars to nearly 200 dollars per tonne of carbon. The Galley and Bataille [1] report based on the results of the IEPE Poles model, considers that the value of 100 dollars by the year 2030 would be reasonable.

There is an average cost equal to one half of this value of the marginal cost, equal to 50 dollars [2].

(1) National Assembly Report No. 1359 (1999) Costs of electricity generation.
(2) Quantity/cost of avoided carbon curves are concave.

The marginal cost of avoided carbon could reach significantly higher values at the end of the chosen period (2050), for example 300 dollars, and the corresponding average cost would be of the order of 150 dollars per tonne because it is known that the marginal costs of initial efforts are very low, or possibly even zero or negative, and that the cost increases as the constraint on emission reductions becomes more severe.

But the cost will also depend on how the negotiable permits market develops. Under these conditions, it is proposed to adopt a range of average costs varying between 400 and 1 000 Francs (60 to 150 dollars) per tonne of carbon to cover these different possible variations.

The international literature does not contain any cost data for « nuclear waste », according to the meaning adopted for the purposes of this report (transuranic elements, namely Pu + minor actinides) comparable to available figures for carbon. The only available measurement is derived from the calculation given in Chapter 1 that gives the value of a tonne of avoided Pu + minor actinides as being equal to the cost of reprocessing used fuels that enabled this reduction. The figures obtained vary from 1.2 billion Francs per tonne to 500 millions Francs per tonne depending on whether or not all reprocessing investments from the beginning are included, or simply the extra cost of keeping the reprocessing option beyond 2010. It is proposed to adopt this range to give an order of magnitude of the cost per tonne of avoided transuranic elements, while emphasising the uncertainty and largely exploratory nature of these figures.

The following table gives the results of some combinations of these various assumptions.

Extra costs for two selected external factors [1]

	H1	H2 EPR	H3 EPR	B2 EPR	B3 EPR	B4	B4 30
Carbon value F 400 /t	570	415	243	284	222	402	658
Pu value F 500 millions/t	183	237	297	206	230	165	102
Carbon C value 1000 F/tonne	1 425	1 037	607	710	556	1 006	1 646
Pu value F 1.2 billion/t	438	568	713	493	551	395	245
High Pu and C total values	1 863	1 605	1 320	1 203	1 107	1 401	1 891
High C low Pu total value	1 608	1 274	904	916	786	1 171	1 748
High Pu low C total value	1 008	982	956	777	773	797	903
Low C and Pu total value	753	651	540	490	452	567	760

(1) from F 400 to 1 000 per tonne of carbon ; from F 500 millions to 1.2 billions per tonne of transuranic elements

Assuming that the values selected for transuranic elements (Pu + actinides) and for carbon remain low for the period, the additional generated cost varies from F 452 billions to F 760 billions for the 2000-2050 period.

In the « constant » assumption, the following extra costs are obtained for the different scenarios.

Constant	**Low transuranic elements, Low carbon**			
Total cost billions of francs	**Initial cost**	**Environment extra cost**	**%**	**Total**
H1	4 989	753	15	5 742
H2	5 105	651	13	5 756
H3	5 065	540	11	5 605
B2	4 288	490	11	4 778
B3	4 275	452	10	4 727
B4	4 225	567	13	4 792
B4 30	4 551	760	17	5 311

Scenarios B2, B3 and H3 are least penalised (10 to 11 % extra cost), and scenarios H1 and B4 30 are most penalised (15 and 17 %) due to the greater use of fossil fuels.

In all cases, the H (high) scenarios are more expensive than B (low) scenarios.

In the different high scenarios, scenario H1 for which the accumulated cost without external effects was the least expensive, becomes more expensive than scenario H3. In the different low scenarios, scenario B3 becomes the least expensive, at 1 % less than B2 and 1.4 % less then B4.

The scenario B2 variant in which RHR1 reactors are introduced only increases the cost by 8 % (to F 4,694 billions) above the approximate accumulated costs estimated in the previous sections (F 4,340 billions). The corresponding increase for the same scenario and EPR reactors is 10 %.

If carbon and transuranic values are both at the top of the range defined above, the extra cost increases from F 1,107 billions in B3 (26 %) to F 1,891 billions (42 %) in B4 30 :

Constant	**High transuranic elements, high carbon**			
Total cost billions of francs	**Initial cost**	**Environmental extra cost**	**%**	**Total**
H1	4 989	1 863	38	6 852
H2	5 105	1 605	31	6 710
H3	5 065	1 320	26	6 385
B2	4 288	1 203	28	5 491
B3	4 275	1 107	26	5 382
B4	4 225	1 401	33	5 626
B4 30	4 551	1 891	42	6 444

The hierarchy between high and low scenarios for a 45 year life of existing nuclear power plants is not changed. Scenario B4 30 becomes more expensive than scenario B4 (45) by 14 %. Scenarios with greatest amount of nuclear power B3 and H3 become the least expensive in their category.

The following result is obtained if the value of carbon remains near the low end of the range and the value of Pu remains high in the long term :

Constant	High transuranic elements, low carbon			
Total cost billions of francs	**Initial cost**	**Environmental extra cost**	**%**	**Total**
H1	4 989	1 008	20	5 997
H2	5 105	982	19	6 087
H3	5 065	956	18	6 021
B2	4 288	777	18	5 065
B3	4 275	773	18	5 048
B4	4 225	797	19	5 022
B4 30	4 551	903	20	5 586

The range of extra costs varies from 18 % for scenarios B3, B2 and H3 to 20 % for B4 30. Scenario B4 is slightly less expensive than B2 (by 1.5 %) and B3 (by 5 %).

Finally, if the value of carbon reaches the high end of the range while the value of plutonium remains low, the advantage of scenarios with a high nuclear content becomes greater.

Constant	Low transuranic elements, high carbon			
Total cost billions of francs	**Initial cost**	**Environmental extra cost**	**%**	**Total**
H1	4 989	1 608	32	6 597
H2	5 105	1 274	25	6 379
H3	5 065	904	18	5 969
B2	4 288	916	21	5 204
B3	4 275	786	18	5 061
B4	4 225	1 171	28	5 396
B4 30	4 551	1 748	38	6 299

For the tension fossil fuel cost assumption (the price of gas doubles during the period), the additional cost of the value of carbon, even at the low end of the range, makes scenarios with a high nuclear component more attractive than scenarios in which nuclear is not renewed at all, as shown in the following table.

Tension	**Low transuranic elements, low carbon**			
Total cost billions of francs	**Initial cost**	**Environmental extra cost**	**%**	**Total**
H1	6 140	1 008	16	7 148
H2	5 879	982	17	6 861
H3	5 468	956	17	6 444
B2	4 878	777	16	5 655
B3	4 726	773	16	5 497
B4	5 089	797	16	5 886
B4 30	5 857	903	15	6 760

Therefore, globally it is found that including external factors induced by application of the principle of caution to nuclear waste and emissions of greenhouse effect gases has important consequences on the total accumulated cost of the different scenarios during the 2000-2050 period.

Within the selected range of values, this means of including external factors increases the advantage of scenarios with low electricity demand and favours scenarios with a high content of nuclear. The example of the balance for the RHR1 variant in scenario B2 or the APA variant in scenario H2 shows the margins for manœuvre and the advantages of developing options specifically designed to reduce the production of waste (Pu + actinides). In the case of B2, external costs are F 148 to 355 billions lower than for the B2 EPR scenario, and in the case of H2 they are F 126 to 302 billions lower than for the same scenario using MOX EPR power stations.

Appendix 1

Scenario S7

What would the material and economic balances have been if the French nuclear power industry had been created without reprocessing and without fabrication of MOX ?

Scenario S7 was built up based on the assumption of zero reprocessing (with no investment in reprocessing plants or fabrication of MOX). Consequently, R & D expenses related to reprocessing, estimated at F 30 billions, have been eliminated from S7.

On the *materials balance*, it is found that scenario S6 (28 MOXed units) would give a saving of 38 000 tonnes of natural uranium and 28 millions UTS compared with scenario S7, over the lifetime of the power plants. It is also better for irradiated UOX, since 40 700 tonnes less UOX is produced. Obviously, the situation is different for irradiated MOX (4 800 tonnes in S6) and the stock of unseparated plutonium and americium.

The cost difference between the *economic balances* of S6 (28 MOXed units) and S7 (without reprocessing) is F 164 billions.

Since the plutonium production in S7 is 153 tonnes greater, the order of magnitude of the cost per tonne of avoided Pu is F 1.1 billion.

Comparing scenario S4 (reprocessing stopped in 2010) with S7, the difference is F 125 billions, so that the cost per avoided tonne is F 1.9 billion. This result is logical to the extent that most investment and dismantling costs for reprocessing are made in S4, but the service life is shortened.

The following table shows :

- accumulated materials balances for S4, S6, S7 ;

- accumulated economic balances for S4, S6 and S7, based on the assumption provided by the ANDRA for the ultimate disposal cost, namely F 850 000 for UOX and F 3.6 millions for MOX, per fuel unit, assuming 55 GWj/t and 50 years interim storage for UOX, and 45 GWj/t and 150 years of interim storage for MOX.

Curves illustrating the variation of stocks of plutonium + americium for the various wastes (irradiated UOX, irradiated MOX, B waste, C waste) for a life time of 45 years for scenarios S4 (reprocessing stopped), scenario S6 (28 MOXed units) and scenario S7 (assumption with no reprocessing) are presented in section 3.3 in the body of chapter 1.

Materials balances

Production	**45 years**			
Generated electricity in TWh	20238			
Needs	**S4**	**S5**	**S6**	**S7**
Natural uranium in ktonnes	460	447	437	475
Enrichment in millions of UTS	330	321	313	341
Production of UOX in ktonnes	56	55	54	58.3
Production of MOX in ktonnes	2.0	3.5	4.8	0.0
Reprocessing in ktonnes	15.0	26.2	36.1	0.0
Interim storage capacity in ktonnes	30-45	20-35	10-25	58.3
Interim storage	**S4**	**S5**	**S6**	**S7**
Depleted uranium in ktonnes	401	389	379	416.6
PWR reprocessing uranium in kt	14.3	24.8	34.1	0
UOX fuels in ktonnes	41.0	28.6	17.6	58.3
MOX fuels in ktonnes	2.0	3.5	4.8	0.0
Stock of unseparated Pu + Am in tonnes	602	555	514	667
Ultimate disposal of waste	**S4**	**S5**	**S6**	**S7**
B waste in m^3 (reprocessing)	11 786	14 825	18 091	0
B waste in m^3 (operation)	20 000			
C waste in m^3 (glass)	1 601	3 325	4 808	0

Source : the« Nuclear Facilities currently in existence » Group

Economic balance

In billions of Francs	**S4**	**S5**	**S6**	**S7**
Capital investments	470	470	470	470
Immediate dismantling (Dmt I)	128	128	128	128
Later dismantling (Dmt D)	112	112	112	112
R&D	100	100	100	70
subtotal investments (Dmt I)	***698***	***698***	***698***	***668***
subtotal investments (Dmt D)	***682***	***682***	***682***	***652***
Operation	1 109	1 109	1 109	1 109
Post-operation	66	66	66	66
Upkeep	122	122	122	122
Subtotal operation	***1 297***	***1 297***	***1 297***	***1 297***
Front end 1977-1998	271	271	271	271
Front end 1999-2049	331	318	307	340
Subtotal cycle front end	***602***	***589***	***578***	***611***
Back end 1977-1998	93	93	93	0
Back end 1999-2049	102	139	170	86
Subtotal cycle back end	***195***	***232***	***263***	***86***
End of cycle waste B + C	18	27	35	5.6
End of cycle irradiated fuels	94	82	72	111
subtotal end of cycle	***112***	***110***	***107***	***116***
subtotal back end + end of cycle	***307***	***342***	***370***	***203***
subtotal cycle	***909***	***931***	***948***	***814***
Total (immediate dismantling)	**2 904**	**2 926**	**2 943**	**2 779**
Total (later dismantling)	**2 888**	**2 910**	**2 927**	**2 763**
Electricity generation	20 238	20 238	20 238	20 238
Average cost per kWh in cts	***14.27***	***14.38***	***14.46***	***13.65***

Source : the « Nuclear Facilities currently in existence » Group

Appendix 2

Comparison of scenario B4 30 with the cases of Germany and Sweden

Case of Germany

The agreement in principle concluded on June 14 2000 between the German federal government and the three main German electricity producers (RWE (including VEW), E.ON (merge of VEBA and VIAG) and EnBW [1] – includes the following main provisions:

- a ceiling to the right to generate electricity expressed in TWh por one nuclear reactor determined, based on an average life of 32 years and assumptions about the production coefficient based on the best five years for each reactor between 1990 and 1999, increased by a factor of 5.5% ;
- nuclear operators can transfer generation rights from one reactor to the other, due to flexibility with their various reactors ;
- the safety of nuclear reactors is « frozen » at their existing levels.

Germany's nuclear power plants include 15 PWR reactors and 6 BWR reactors, with a total installed capacity of 22.3 GWe. The average age is 18.5 years.

Under this agreement, five nuclear reactors are likely to be shut down shortly :

- the three oldest and lowest power reactors at Obrigheim (EnBW), Stade (E.ON) and Brunsbuttel (HEW) ;
- 1 reactor, Mulheim Karlich, shutdown for several years since its operator, RWE, had been authorized to transfer generation rights of 107 TWh to its other reactors ;
- the reactor in Biblis A (RWE), due to strong local opposition.

(1) EDF has recently taken a 25 % share in EnBW's capital.

- Comparison of scenario B4 30 -

Considering the intrinsic flexibility of the agreement, two assumptions can be made about criteria adopted by German electricity producers for the 15 nuclear reactors still in service after 2002 :

- keep the most recent reactors in service for as long as possible
- keep reactors with the best performances for the agreement reference period, namely 1990-1999.

The following table contains forecast shutdown dates for the different reactors for the two assumptions mentioned above, respecting production rights for each nuclear operator.

				Forecast reactor shutdown date	
Electricity producer	Reactor	Age years	Power capacity MWe	keep the most recent reactors	keep the highest performance reactors
E.ON	Stade	28	640	2002	2002
	Isar1	22	870	2008	2010
	Unterwese	21	1285	2012	2011
	Grafenrheinfeld	18	1275	2015	2014
	Grohnde	15	1360	2020	2018
	Brokdorf	13	1370	2022	2020
	Isar 2	12	1380	2023	2021
RWE	Mulheim Karlich	13	1219	2000	2000
	Biblis A	25	1167	2002	2002
	Biblis B	23	1240	2013	2012
	Gundremmingen B	15	1284	2022	2021
	Gundremmingen C	15	1288	2022	2021
	Emsland	11	1290	2026	2025
EnBW	Obrigheim	31	340	2002	2002
	Philippsburg 1	20	890	2010	2012
	Philipsburg 2	15	1358	2020	2018
HEW – E.ON	Brunsbuttel	23	771	2002	2002
	Krummel	16	1260	2020	2017
NWS	Neckar 1	23	785	2007	2010
	Neckar 2	11	1269	2026	2023

Reference: CEA/DSE/SEE Élecnuc

Considering the shutdown dates mentioned above, the average life of existing German nuclear power stations should be 32 years if Mulheim Karlich is included, in accordance with the text in the June 2000 agreement, and 33 years if Mulheim Karlich is not included.

German nuclear power will drop by 25 % by 2010, and will drop to 50 % only about 2020. The average life of several reactors should be more than 32 years, possibly as much as 37 years.

The net remaining producible energy to be produced on 1/1/2000 is 2 623 TWh, the ceiling being fixed by the agreement. The total amount to be produced by German nuclear power stations would be 4 650 TWh, equivalent to 23.8 years of production of the plant operating at full capacity.

Case of Sweden

The case of Sweden is different because 2010 was fixed as the nuclear shutdown date in the 1980 referendum. 60 % of Swedish nuclear power stations were put into service during the 1980s.

Assuming that all reactors commissioned before 1980 are shutdown after a 30 year life time and that the other reactors will be shutdown on 1/1/2010 [1], Swedish nuclear power plants (including Barseback 1 that was shutdown in November 1999) should produce 1 854 TWh, namely 21.0 years of production operating at full power.

Comparison with scenario B4-30

Scenario B4-30 selected by the mission is equivalent to a decision to shut down each existing nuclear reactor 30 years after its commissioning.

The differences between this scenario and the German agreement are that this scenario includes a fixed shutdown date without considering the history of each reactor, without any improvements to operation and without the possibility of transferring production rights from one reactor to another. Furthermore, this scenario does not mention anything about « freezing » the safety level of existing reactors.

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(1) This assumption for shutting down reactors commissioned in the 1980s at the same time on 1/1/2010 is probably not realistic since it would require that Swedish electricity companies would make massive investments in the previous years.

- Comparison of scenario B4 30 -

The difference between this scenario and the case of Sweden is that the scenario does not have any limit date except for the date deduced from the most recent industrial commissioning, probably the Civaux-2 reactor that should occur before the end of the year 2000.

The production factor for the french PWR power stations (apart from the 4 reactors in the N4 series that have not yet started industrial service) is lower than the production factor for the Swedish and German power stations both during recent years and as an accumulated value.

Kp	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**accumulated from commissioning to end of 1999**
Germany*	72.24 %	75.41 %	78.55 %	82.78 %	78.56 %	82.40 %	74.55 %
France	68.62 %	72.12 %	74.54 %	72.51 %	73.30 %	72.37 %	67.87 %
Sweden	80.34 %	76.84 %	80.87%	76.41%	80.36%	79.90%	74.96 %

* *including the Mulheim Karlich reactor that has been out of production since 1994*

The net producible energy remaining to be produced from nuclear power stations after January 1 2000 in the case of scenario B4-30, compatible with future electricity demand assumptions for France, would be 5 578 TWh. This producible energy does not include exports, if any, during this period. Considering previous production by nuclear power plants before January 1 2000 (5 300 TWh), the total production of power plants within this scenario would reach 10 900 TWh corresponding to 19.7 years equivalent full power operation. As a reminder, the life mentioned in the document submitted to the French safety authorities is 32 years equivalent full power operation.

Note

The B4 45 years scenario would result in total electricity generation from existing nuclear power stations equal to 16 660 TWh, apart from exports during the period beyond 2000, namely 30.1 years equivalent full power operation.

Appendix 3

Recycling reprocessing : international situation

Only five countries in the world are now operating nuclear fuel reprocessing plants, apart from military installations and installations related strictly to supergenerator programs.

France is the leader in this field with two plants (UP2-800 and UP3) in La Hague with a total annual reprocessing capacity of 1 700 tonnes of used fuel from light water reactors (LWR). The **United Kingdom** has two plants in Sellafield, the B-205 for used fuels from Britain's Magnox reactors with a capacity of 1 500 t/year, and Thorp for fuels from PWRs (900 t/year). **Russia** has a reprocessing capacity of 200 to 400 t/year for used fuels from LWRs (VVER-440), in Cheliabinsk. **India** has two plants with at capacity of about 125 t/year, but only operates the most recent plant (Kalpakkam). Finally, **Japan** operates a demonstration plant (90 t/year), mainly for used fuels from LWRs.

Several plants have been shutdown - one in the United States, and one experimental plant in Germany, the Eurochemic plant in Belgium and finally UP1 in Marcoule, France.

Two completed or almost completed plants have never been commissioned, one in the United States and the other in Germany.

There are two plans for commercial plants (in Krasnoyarsk in Russia and Rokkasho Mura in Japan), but it is by no means certain that the Russian plant will be completed. On the other hand, commissioning of the Rokkasho Mura plant (800 t/year) is still planned for 2005, but could be delayed once again. Furthermore, China is preparing to commission a demonstration plant with a capacity of about 50 t/year.

At the moment, apart from countries with their own reprocessing industry, there are only a few countries with nuclear power plants that reprocess their used fuels in other countries : the most important are **Germany, Belgium and**

Switzerland. But these three countries have now initiated policies to stop reprocessing that should come into effect after termination of existing contracts. The **Netherlands**, which now only has one reactor in operation, also has its used fuel reprocessed. Some other countries (**Sweden, Italy, Spain, etc.**) had some of their used fuels reprocessed in the years around 1975 and in the 1980s, and then abandoned this option. Finally, **Japan** reprocesses a large portion of its used fuels in French and British plants. In France, EDF has already initiated a dual management policy for the cycle back end. British Energy in the **United Kingdom** announced its intention to gradually stop reprocessing its used fuels by March 2000.

Although only a minority of countries with nuclear power stations have chosen the reprocessing at the moment, existing and programmed industrial reprocessing capacities are not sufficient to manage all the used fuels in these countries.

At the moment, France is the only country that is close to a balance between separated and recycled flows of plutonium, by annually adapting quantities of reprocessed UOX to loaded quantities of MOX, but accumulated stocks of plutonium are still large [1]. On the other hand, the reprocessed uranium is not fully used due to the lack of a clearly defined short-term industrial program.

Only four countries have MOX fabrication plants for light water reactors, namely France (CFCa in Cadarache, 40 t/year and Melox in Marcoule, capacity about 160 t/year but only 115 t/year authorised), Belgium (Dessel, 35 t/year), Japan (Tokai Mura, 40 t/year) and the United Kingdom with its Sellafield pilot plant (8 t/year), plus a 120 t/year plant of which commissioning is delayed by many difficulties encountered over the last few months by the operator, BNFL.

Japan and Russia also have plans for commercial plants.

A total of more than 30 reactors have been MOXed in Europe (Germany, Belgium and Switzerland and most of them, 20 reactors in France). The United Kingdom does not use its separated plutonium. The few MOX programs in place outside Europe are still experimental. Russia is planning a MOX program, but mainly in order to recycle weapons grade plutonium. There is an ambitious

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(1) The balance is now about 8.5 tonnes of Pu output from reprocessing and recycled in MOX per year. In all, more than 40 tonnes out of the approximately 84 tonnes of plutonium that France has separated on its own behalf since 1965, have not been recycled in a reactor.

program in Japan, but there are many of difficulties with it and at the moment MOX is not used in any reactor.

Appendix 4

Proliferation

By definition [1], nuclear proliferation is the dissemination of materials, techniques and know how in order to make nuclear weapons. A distinction is made between horizontal proliferation which leads to an increase in the number of States with the capability of having a nuclear weapons program, and vertical proliferation in which the performances of nuclear weapons are improved. Non-proliferation includes all international instruments due to prevent dissemination of nuclear weapons such as the non-proliferation treaty, treaties creating areas free of nuclear weapon such as the Tlatelolco, Rarotonga and Pélindaba treaties, and rules (not restrictive) set down by the Zangger and NSG committees in order to control nuclear exports.

Use of plutonium for military purposes

All the cores of nuclear reactors produce plutonium, which theoretically could be used for military purposes.

However, there are several grades of plutonium distinguished by their isotopic composition, and particularly by their content of the 239 isotope, which is fissile. Armed forces make weapons in using plutonium containing more than 90 % of this 239 isotope, while plutonium recovered after reprocessing of the irradiated fuel removed from pressurised water reactors only contains about 60 % of the 239 isotope.

Furthermore, this plutonium contains significant quantities of plutonium 240 to 242, which are undesirable for military applications, and many impurities that are also undesirable for this purpose.

However, since the isotopic composition of plutonium depends on the type of reactor in which it is produced, on the type of used fuel and on the rate of irradiation of this fuel, some nuclear power generation systems have been preferred due to their ability

(1) Definition taken from the 1995 Encyclopédie Universalis.

to produce weapons grade uranium. This is the case particularly for the old French UNGG system, the Russian RBMK system and the Canadian CANDU system.

There is therefore a danger that exported civil reactors could be used for military purposes, but the international community has taken a number of guarantees. For example, preventive measures consist of asking purchasing countries to sign the non-proliferation treaty. In signing this treaty, the states without nuclear weapons agree to not attempt to develop or purchase nuclear weapons and to put all their nuclear installations under the control of the IAEA which was created in 1957 to monitor these installations.

The policy of preventing diversion of civil materials for military purposes is still a priority, but inspections are difficult. The discovery of Iraq's clandestine nuclear program, and the impossibility for the IAEA of verifying the initial declaration made by North Korea, have cast some doubt on the reliability of these inspections and obliged Member States of the Agency to find a solution by adopting the « 93 + 2 » program to strengthen guarantees.

Proliferation is inherently an international risk that the international community has faced since the beginning of civil nuclear power. It was attempted to find a solution as early as 1968, by proposing the « Nuclear weapons non-proliferation treaty » to the various countries, that limited the number of States authorised to possess nuclear weapons to five and prevented other countries from possessing them, however confirming their inalienable right to pacific applications of nuclear energy and a commitment by the signing states to facilitate technical exchanges in this field. This treaty encourages access of signatory states to nuclear technologies, provided that, the states without nuclear weapons renounce to them, and that they sign general guarantee agreements. It simply and permanently limits the number of States authorised to hold nuclear weapons to five.

The nuclear weapons non-proliferation treaty

This treaty was adopted and available for signature on July 1 1968, and made a distinction between countries with nuclear weapons defined as the States who had carried out nuclear experiments before January 1 1967, and other States that are governed by different rights and obligations.

States without nuclear weapons that have signed the Treaty make a commitment to not attempt to develop or purchase nuclear weapons and to place all their nuclear installations under the control of the IAEA. Obviously, these commitments cannot be imposed on non-signatory States such as India and Pakistan.

States possessing nuclear weapons commit themselves to facilitate exchanges of equipment, materials and scientific and technological information to enable the use of nuclear energy for peaceful purposes. Furthermore, all signatories to the Treaty agree to continue negotiations to end the nuclear weapons race, and to achieve general and complete disarmament under strict international control.

France agreed to join the Non-Proliferation Treaty in 1992, and it was signed by 178 countries just before the extension conference that was held in New York from April 18 to May 12 1995. This conference reinforced actions to prevent nuclear proliferation. It was decided to extend the Non-Proliferation Treaty indefinitely by consensus, in return for progress made towards achieving the objectives of the treaty according to a three-point program :

- conclusion of the « Complete Test Ban Treaty » in 1996. This treaty is still not in force, it must be ratified by at least 44 countries including India, Pakistan, Israel and the United States [1] ;
- negotiation of a Fissile Materials Production Ban Treaty (TIPMF): a resolution made by the disarmament conference on August 11 1998 fixed the mandate of the negotiations beginning in 1999 ;
- continuation of negotiations to reduce the nuclear arsenals of States possessing nuclear weapons.

Significant progress has been made on these three points.

Subsequent to the Iraqi experience, IAEA Member States negotiated an additional protocol called « 93 + 2 », in order to detect any clandestine activities.

The five declared nuclear powers (United States, Russia, France, United Kingdom and China) also jointly renewed security assurances given to non-nuclear States that have signed the non-proliferation treaty.

Furthermore, the non-proliferation treaty was completed by regional agreements creating « nuclear weapon free areas ». Thus France ratified the Rarotonga Protocols applicable to the South Pacific on September 20 1996.

(1) Ratification is still blocked by American Congress.

Appendix 5

Nuclear safety

Nuclear safety is intended to protect persons and the environment against all dangers and nuisances related to nuclear activity.

It satisfies three needs, namely to guarantee the safety of nuclear installations during normal operation by limiting releases of radioactive effluents into the environment, preventing incidents and accidents, and limiting the consequences of these events. It includes all risks inherent to the installations, from design to dismantling, and the use, transport and transformation of radioactive substances.

In order to make a nuclear installation safe, it is essential to be able to control the nuclear reaction at all times, including cooling of the fuel and confinement of all radioactive products. These three fundamental functions govern the design, then the construction and finally operation of a nuclear power station.

Different international authorities, such as the International Atomic Energy Agency (IAEA) and the *OECD Nuclear Energy Agency (NEA) contribute to nuclear safety.*

IAEA activities in the nuclear safety field are intended to inform and promote practices in order to achieve and maintain the safety of nuclear installations at a high level in all countries concerned.

These activities consist mainly of :

- the organisation of study groups at different levels and writing texts called « safety standards » describing safety principles and practices; Member States can use these texts as a basis for their national regulations. Since the beginning of 1996, this activity has been monitored by the Advisory Commission on Safety Standards (ACSS) that is composed of the highest level representatives of Regulatory authorities in member countries and is responsible for making reports to the Agency General Manager. These

« safety standards » are approved by the ACSS and are published under the responsibility of the IAEA General Manager ;

- providing Member states with « services » to offer an opinion on particular aspects affecting safety.

The NEA (Nuclear Energy Agency) created in 1958 includes all OECD countries except New Zealand and Poland. Its main objective is to promote cooperation between the governments of participating countries for the development of nuclear energy as a safe, and environmentally and economically acceptable energy source.

National Safety authorities within the NEA participate particularly in the work done by the different committees or work groups.

These include a group that examines problems related to radioactive waste (RWMC = Radioactive Waste Management Committee) and that includes Safety authorities and organisations responsible for waste management.

Furthermore, several agreements have been negotiated within countries concerned by nuclear power.

Nuclear safety conventions

The convention on nuclear safety was negotiated after the Chernobyl accident. Its articles describe good practice on the safety of fixed civilian reactors for generation of electricity. In ratifying the convention, the signing parties agree to produce a report describing the manner in which they implement these good practices. The convention came into force after it was ratified in twenty-two countries (including seventeen « nuclear » countries) in October 1996.

The common convention on safe management of used fuel and safe management of radioactive waste is the keystone of the convention on nuclear safety for used fuel and radioactive waste management installations. It will come into force when it has been ratified by twenty-five states, including fifteen with at least one nuclear power station in operation. It had been ratified by thirteen countries by the end of 1999, including nine that had at least one nuclear power station in service. France has terminated its approval process and its approval « instrument » was sent to the General Manager of the International Atomic Energy Agency in Vienna on April 7 2000.

Furthermore, the Western European Nuclear Managers Association (WENRA) was formally created in February 1999. It includes the top managers of the safety authorities in Germany, Belgium, Spain, Finland, France, the Netherlands, Sweden, Switzerland and the United Kingdom. Its objectives are to :

- develop a common approach towards nuclear safety and its regulation, particularly within the European Union ;
- set up an independent capability for the European Union, so that it is able to examine problems related to nuclear safety and its regulation in candidate countries to the Union ;
- evaluate and implement a common approach for problems arising in the field of nuclear safety and regulation.

1999 was marked by accelerated discussions with Eastern European countries wishing to join the European Union. Even if nuclear safety is not strictly speaking a community criterion, it is obvious that the criteria for joining the European Union must take into account the safety of nuclear power stations in these countries. Furthermore, the prospect of joining the union is a strong argument to close the least safe power stations as quickly as possible.

The WENRA association published *a report on nuclear safety in Eastern European countries that are candidates for entering the European Union* and that own at least one nuclear power station (Bulgaria, Hungary, Lithuania, Romania, the Czech Republic, Slovakia and Slovenia) in March 1999.

Its main conclusions are :

- all regulatory conditions and all safety authorities have made positive changes in recent years. However, some countries still need to make further progress, and some of these countries may be affected by the economic situation ;
- although a large number of deficiencies in the design of RBMK reactors have been identified and corrective actions have been undertaken, the lack of an appropriate confinement remains a major problem that cannot be solved realistically: this observation concerns all reactors in the RBMK system ;
- VVER 440-213 reactors (2^{nd} generation) and VVER 1000 reactors can be brought up to a safety level similar to the same generations of Western reactors, if some improvements are made ;
- based on information that it was able to verify, the WENRA association was unable to reach any conclusion about VVER 440-230 reactors (1^{st}

generation) ; this applies to reactors 1 and 2 in Slovakia's Bohunice power plant and reactors 1 to 4 in Bulgaria's Kozloduy power plant.

International cooperation has been setup to improve the safety of nuclear reactors in Eastern Europe.

Safety actions in Eastern European countries carried out within the framework of the European Phare and Tacis programs and projects organised by the European Bank for Reconstruction and Development (EBRD), were marked by strong cooperation between the IPSN and the GRS, the two main players in the European technical safety organisations group (TSOG), that are coordinated by their subsidiary, Riskaudit.

The objective is to carry out specific cooperative efforts to contribute to strengthening the Safety authorities in these countries and their technical support organisations, and to improve safety in the installations. Activities in these fields are concentrated on :

- the transfer of Western methods and regulatory practices, mainly for the benefit of the Ukrainian safety authority ;
- the transfer of analysis tools (Cathare, Escadre and Icare) to Ukrainian and Russian technical safety organisations ;
- various safety evaluation work being done to assist Armenian, Russian, Slovakian and Ukrainian safety authorities. These evaluations apply to pressurised water reactors (VVER), pressure tube reactors (RBMK) and the Chernobyl sarcophagus.

Finally, since 1998 the IPSN and the GRS have been working to implement the three parts of the Franco-Germany initiative for Chernobyl dedicated to safety of the « sarcophagus », transfer of radioelements into the environment and the health of populations. An agreement signed in Kiev in 1997 about Chernobyl power station deals with pooling of data collected by the various Ukrainian, Byelorussian and Russian Institutes. The total budget is about 40 million Francs over three years, distributed equally between France and Germany, with electricity producers in each country making a contribution.

Safety in the East

Safety problems related to existing RBMK and VVER reactors in Eastern countries are related to the generic characteristics of these reactors.

The 14 RBMK reactors in operation belong to three different generations and were built to different series of safety standards in the former Soviet Union. There are very considerable differences between the various RBMK reactor systems, and even significant differences between reactors in the same series.

However, the basic elements of the core design, the design of the reactor block and the primary circuit are common to all RBMK type reactors. This means that some specific safety problems are common to all units.

The most important safety problem related to the design is the complete or partial lack (depending on the series) of a confinement containment for the primary circuit. The reactor core is contained in a separate cavity designed to handle serious damage. Unlike Western designs, the reactor vessel is not contained inside a containment designed to confine all the energy that could be released during an accident.

For VVERs, there are two generations of VVER 440 reactors that were designed using different safety philosophies. Eleven reactors in the oldest generation, VVER 440/230, are still in operation, and five have been permanently shutdown. Fifteen units in the second generation of type 440/213 VVERs are now in operation.

Candidate countries to the European Union have :

- *Six type 440/230 VVER units*, including four in Bulgaria and two in Slovakia.

Some systems in the original design of these power stations were not suitable for resisting potential accidents and their safety is unacceptable according to standards in force in Western Europe.

However, significant modifications (to varying degrees) to the original design have been made to all VVER 230 reactors currently in operation.

- *Eleven type 440/213 VVER units*, including four in Hungary, four in the Czech republic and four in Slovakia.

Although the original design included safety problems that were unacceptable according to standards in force in Western Europe, improvements and modifications have been made on all reactors to solve most safety problems.

One general unsolved problem is related to the efficiency of the reactor containment during design accidents. The corresponding experimental tests are planned within the framework of the Phare project.

If it is possible to clearly demonstrate that confinement functions are effective, it should be possible to increase the safety of VVER 440/213 reactors to a level comparable to what is found in many power stations currently in operation in Western Europe. This improvement should solve all safety problems notified by the IAEA.

• *Two type 1000/320 VVER units* in operation, both in Bulgaria. Two other units with a similar design but with major modifications are under construction in the Czech Republic.

The original design includes weaknesses that are not acceptable according to recommended standards in Western Europe. Improvements or modifications aimed at solving problems due to this design are being made in all power stations.

The safety of VVER 1000 units can be improved and brought up to a level comparable with the level of many power stations in operation in Western Europe. This improvement should concern all safety problems identified by the IAEA.

The development of multi-lateral authorities (UNO, miscellaneous associations) and multi-lateral nuclear safety conventions clearly shows that the concept of safety in civilian nuclear installations is clearly becoming much more international, although no restrictive agreements have yet been made.

Appendix 6

Variation in the underlying price of energy

This variation depends on the interaction of three series of factors over the very long term (50 to 70 years) :

- The change in the energy wellhead cost, which depends basically on future technical progress.

- Global pressure on energy demand for each energy form, which depends largely on four main parameters at world level :
  - demographic growth ;
  - assumed growth in the world economy, and by geographic area ;
  - the impact of technical progress on transformation equipment and energy consumer equipment ;
  - public policies related to infrastructures, environmental standards, tax and procurement security.

- The strategy of players (oil exporting countries, multinational companies) whose actions can have a significant influence on the supply of energy on the market (diversification, concentration, collusion).

Each of these factors need to be analysed briefly before attempting to create different price scenarios.

1 – The cost of access to energy

The main question is whether or not we should talk about possible depletion of ***oil*** and ***gas*** reserves by the year 2070.

Most geologists observe that the main reason why the reserves/production ratio has grown from 30 years in 1973 to 44 years today, is the upwards re-evaluation of old discoveries. They deduce that the peak production of conventional oil (produced using conventional techniques) will occur in about 2005-2010. This is based largely on the lower efficiency of exploration and the difficulty in finding giant new oil fields.

Industrialists in the sector have realised that fears of depletion such as coal in the 19th century and oil in the 1930s have never been justified in the past, that the worldwide R/P ratio has always oscillated between 25 and 45 years and that price increases make it possible to start new research and discover new oil (as happened when oil prices increased when the rate of increase in demand for oil exceeded the rate of increase in its supply). Technical progress can improve the recovery ratio of the stock in the ground, increase prospecting efficiency (for instance three-dimensional seismic exploration) and make it possible to access more difficult oil fields (horizontal boring). Thus the cost of access to crude oil has dropped by an average of 20 % to 30 % in real terms between 1973 and 1998.

In reality, due to progress with knowledge and technologies, the boundary between conventional oil and non-conventional oil is continuously being pushed back. For example, extra heavy oils in the Orinoco basin (in Venezuela) were considered to be exploitable only at a high price (of the order of $ 30 to 40 per barrel of crude oil) until the 1990s, and are now considered to be economic at a price of the order of $ 15 per barrel. Therefore, there is a continuum of oil resources between easily recovered oil, deep offshore oil, extra heavy oil, tar and bituminous schists and sands. Similarly, Fisher-Tropsch processes used to produce liquid fuels from natural gas or coal liquefaction processes will make it possible to significantly increase proven oil reserves in the future by creating bridges between the various fossil fuels.

Considering the point of view of industrialists, it is assumed that there will be no limitation in oil resources by the year 2070, at least in physical terms, but it will be necessary to use more efficient technologies to access these oils as easily recovered oil becomes depleted. The question of depletion is then transferred to technology ; will these techniques necessarily be more expensive?

Oil companies have different opinions about future changes to the wellhead cost of sub-conventional oil (deep offshore, oil in polar areas) and oil derived from schists, gas and coal deposits. This depends on the efficiency of research and development.

Firstly, technological leaps are possible within this timescale (50 to 70 years) and it is not improbable that oil wellhead costs will progressively drop in real terms over the period, particularly because there are substitute solutions using renewable energy or nuclear power that will apply pressure on costs.

But confidence in progress is not sufficient in itself, and some authors remind us that 75 % of all oil reserves are concentrated in less than 1 % of all known fields [1]. If technical progress is less spectacular than expected and environmental constraints are much stronger than we could have imagined, then obviously it is quite possible that the wellhead cost of new oil will increase significantly, obviously in real terms.

For **gas**, reserves are promising and many geologists confirm that they should be significantly greater than oil reserves. But the cost of delivering this gas depends largely on the cost of its transport.

The same is true of ***coal*** : reserves are abundant : the R/P ratio is greater than 200 years. The cost of production may be very low in the case of coal extracted from open cast mines (2 to 3 times less expensive on average than coal extracted from underground mines). The proportion of coal extracted from open cast mines is continuously increasing in the world, which tends to force prices downwards. This trend should continue and the proportion of coal extracted from open cast mines increased from 22 % in 1970 to 50 % in 2000, and could continue to increase. But the competitiveness of coal will depend in particular on the costs of transport, and here again technical progress should reduce logistics costs (particularly for sea freight).

In other words, the abundant reserves of coal and gas (accessible at modest cost) could act as a policeman on the international energy market and prevent strong increases in the price of crude oil, while encouraging oil companies to carry out R & D to lower the oil wellhead cost.

2 – Energy efficiency in consumption

Several world energy demand scenarios need to be produced if we want to consider the entire range of possibilities. There are strong uncertainties about the growth rate in Northern countries and in Southern countries. There is a great deal of debate about the rate of increase in the world population. Starting from a

(1) All oil companies know that there is a very large number of small fields and very few giant fields. As L. Weeks writes « very rich areas are often much richer than we dared to imagine, and most are poorer than we would have liked. The concept of an average value is not very meaningful in geology … ».

world population of six billions persons in 2000, many people forecast that the most probable value for the population in 2050 is 8.9 billions, but this value is associated with two other assumptions, a high assumption (10.7 billions) and a low assumption (7.3 billions). Looking at these figures, a population of 10 billions in 2070 would appear to be reasonable.

Is the available energy supply sufficient to satisfy the needs of this population?

The problem should be stated in economic terms rather than in physical terms ; at what price could this energy be provided? Here again, technical progress remains the main uncertainty since energy needs and the energy supply will depend fundamentally on technical progress observed on the demand side. There is no reason to suppose that the long-term trend in improving the energy efficiency of the GNP will be interrupted. But new needs will appear, related to equipment that is not known at the present time. And on the supply side, some of the major innovations such as fuel cells are discernible at the moment.

Many other major innovations make up challenges for transformation, transport and the use of energy. Thus, the coming out of superconductors with a high critical temperature opens up practical prospects, and new power photovoltaic sensors also could produce competitive energy by the year 2050. Increasingly strict environmental constraints will drive research in transport and electricity consumer equipment. There are still enormous potential savings in efficiency using existing technologies, and we have to believe that the increasing needs for goods and services will be accompanied by much more efficient new technologies being brought onto the market. Therefore it is reasonable to be optimistic in this sense.

3 – The strategy of the players

Geography cannot be ignored : 3/4 of ***oil*** reserves are located within OPEC countries and 2/3 of these reserves are in the Near East. Saudi Arabia alone holds 25 % of these reserves (almost 10 % in Iraq, 10 % in Iran and 10 % in Kuwait). OPEC production quotas were respected during the last months of 1999 and the beginning of 2000, illustrating that the result can be profitable in terms of income for oil producing countries. Much of the increase in the price of crude oil in recent months is explained by good discipline ; therefore, there is no reason to exclude collusion strategies that could keep crude oil prices well above production costs.

But would this configuration be sustainable in the long term? It is very doubtful, to the extent that any long term increase in prices above wellhead costs would result in substitution by other energies. The ***coal*** market is a very competitive market, on which there is a large number of modest sized fields and it would be difficult to justify any idea of collusion. Coal reserves and gas reserves are less unevenly distributed than oil reserves, and it is probable that these two markets would provide protection against an artificial and long-term increase in the price of crude oil. This does not mean that there will not be any temporary price increase, but the trend will continue to be that prices will match costs. The 1983 counter oil shock (followed by the price war in 1986) that followed the second oil shock (1979-1981) showed how an unjustified and excessive increase in the price of oil will inexorably cause a change in the market. Therefore, it is reasonable to be confident that prices will match costs in the long term, although that does not mean that some market configurations would not cause price movements unrelated to costs in the short term.

But when considering costs, external factors need to be taken into account, and will become more important in the future than they are at the moment. Strengthened environmental concerns will oblige players to respect increasingly strict standards, environmental taxes will be higher, and players will have to purchase rights to pollute that will no doubt be more expensive. This will affect costs but will also increase efficiency. Therefore in our scenarios, these external costs will increase more or less quickly, and no doubt the public desire to preserve the environment and encourage long-term development is an element that should not be underestimated in the debate. The State is a player that will affect the price of energy in the future both as a market regulator and tax collector.

Starting from these considerations, and despite very strong uncertainties, it is possible to suggest a few energy price scenarios that should be seen as images of possible futures, rather than forecasts of a probable future.

Appendix 7

Taking into account external factors

An external factor may be considered as a failure of the price system in a market economy. All costs and advantages are not included when determining the cost price of an activity and therefore there is a difference between the « private cost » observed on the market and the « social cost » paid by the community. External factors need to be made internal in order to make the two prices coincide, and the only ways to do this are regulation (fixing standards or bans by public authorities), setting up a tax (the "polluter pays" principle), or the use of a "right to pollute" market (the State fixes the acceptable amount of pollution and the various players purchase rights on the market, the price of the rights depending on supply and demand).

Therefore, external factors represent a failure of the market, but the market can be a means of solving these problems to the extent that it is a way to establish rights of ownership that had been badly defined in the past.

These external factors may be considered either locally (geographically well delimited pollution), or on a worldwide scale.

With the climatic risk (greenhouse effect), and the management of nuclear waste, *three* new *dimensions* now need to be taken into consideration :

- the worldwide nature of the risk ; the problem is inherently planetary and therefore its solution can only be found through an international will to cooperate ;
- the quasi-irreversible nature of the observed effects. The problem is basically a very long-term one involving future generations, and any choice introduces a great deal of inertia ;
- the magnitude of the uncertainties involved. The state of scientific knowledge at the present time makes it impossible to evaluate the nature of the risks involved. Hence the need to clearly dissociate risks from which we can protect ourselves (insurance and long term contracts), from major uncertainties for which decision makers are unable to find a solution since

> they need to act with very imperfect information (for which it is impossible to determine an objective probability). The irreversibility concept defined by C. Henry according to which uncertainty could be at least partially reduced by scientific information, means that the decision maker needs to keep several options open.

The introduction of « option values », in other words an availability to pay to keep an option open, is a way of waiting for more information to be acquired before making a final decision. In this sense, it induces a flexibility factor in public choices. We can even take account of « existence values » if we are ready to pay to avoid the disappearance of some elements from the world heritage, although there is no certainty about the use of these elements : ideally, the value of an arbitrary asset is the sum of three elements, namely its usage value, its option value and its existence value.

The main difficulty is to measure and put a price on these external factors, and this difficulty increases as the uncertainty about the potential effects increases ; it often arises due to the lack of a market through which a monetary value can be assigned to these effects. There are several techniques for getting round this difficulty, for example the surplus method, the defensive expenses method (avoidance cost logic), the hedonistic prices method and contingent evaluation. Contingent evaluation involves direct questioning to determine the maximum amount that persons are prepared to pay to benefit from a better quality of the environment, or the minimum amount that these individuals are ready to pay to renounce this increase in quality. All these methods have advantage and disadvantages, and one or another method will be preferred depending on the case.

Another difficulty is the choice of the discount rate. Economically, reducing future values by introducing a value of time can be justified, but this causes problems when considering the very long term. Even with a very low rate (1 %), consequences that occur several decades or centuries in the future no longer have any present value. We might always think that future generations will be richer and will have benefited from technical progress that will enable them to face these consequences. But this optimistic view is debatable. On the other hand, not discounting at all means sacrificing the present generation. Considering these factors, we can modulate the discount rate according to the nature of the external factors, but this approach is contested by people who claim that the only way of making optimum choices is to use a single discount rate. Therefore, a second best solution is to quantify external factors in physical terms (spilled pollutants, waste to be stored, etc.), and not to use monetary factors (discounted) until as late as possible in the economic calculation.

Two problems deserve special attention ; firstly determining the price of a tonne of carbon for approaches that take into account the greenhouse effect, and secondly determining the value of external factors related to the generation of electricity for different competing technologies.

1 – The greenhouse effect : what value for carbon?

The objective of the 1997 Kyoto protocol following on from the outline convention adopted in Rio de Janeiro in 1992, was to stabilise concentrations of greenhouse effect gases (6 gases are concerned) at a level that « *prevents any dangerous anthropic disturbance to the climatic system, ensures that changes occur over a time span sufficient for ecosystems to be able to adapt naturally to climatic changes, does not cause any threat to food production and enables sustainable economic development* ». The world is divided into two parts, firstly "Appendix I" countries (OECD countries and countries in transition from the ex-Soviet block) and the others. Only the first countries have made quantified commitments. For an average reduction of emissions during the 2008-2012 period to 5.2 % below the 1990 values (for these Appendix 1 countries), Europe is required to achieve – 8 %, the United States – 7, Russia 0, and Australia + 8 %. Within the European Union, the distribution of commitments are + 27 % for Portugal, 0 for France, - 21 % for Germany. The value of 0 % for France starting from the 1990 value actually corresponds to -10 % from its trend up to 2008-2012.

The Protocol implemented several instruments for reducing greenhouse effect gases :

- "*joint application*" between parties mentioned in Appendix I. It may be less expensive for an Appendix 1 country to reduce CO_2 emissions by investing in another Appendix 1 country rather than at home, which is collectively preferable ;
- the "*clean development mechanism*" that enables a developing country to achieve sustainable development while enabling an Appendix 1 country to satisfy its emission reduction commitments ;
- a "*negotiable rights*" (or permits) market for parties who have signed the Kyoto Protocol.

Therefore, in order to direct investment choices towards projects that are economic in terms of emissions of greenhouse effect gases, there is a need to determine the « value of carbon ». This value corresponds to the cost of the actions necessary to avoid putting one tonne of carbon into the atmosphere (or to absorb carbon in « pits »). Optimally, this value is obtained by finding the intersection point between the marginal cost of emission reductions and the marginal benefit of emission reductions (marginal cost of avoided damage). Curves of marginal costs of emission reductions can be studied for each region in isolation and for a consolidated region (or bubble). Assuming that the flexibility provisions defined in the Kyoto protocol work perfectly (exchanges of emission permits possible with no limitations), the national value of carbon is exactly the same as its international value. Otherwise (fixed ceilings to permit exchanges), there will be several values of carbon that will differ according to the country.

Simulations made using different models (including the POLES model) show that national values of carbon vary from US$ 150 to 300 (1990) in the United States, US$ 194 to 700 in Japan, and from US$ 160 to 327 in the European Union. In France, values vary between US$ 212 and 226 per tonne of carbon. If it becomes possible to exchange emission permits, the international value of carbon will drop, and will drop further as the permits market expands. In an « appendix B » market configuration, Patrick Criqui mentions that models predict an international value per tonne of carbon between US$ 70 and 150 (at least if CO_2 alone is considered). The value of a tonne of carbon drops to a range between US$47 to 68 if the other greenhouse effect gases are included.

In the case of a genuine world market, new opportunities for reducing greenhouse effect gas emissions will appear at lower cost and the « prices » per tonne of carbon will be able to drop below US$ 25. A region that is more economic in energy will emit less carbon per unit of GNP, and the marginal cost per tonne of emission reductions is likely to be higher. This is why it is useful to make exchanges, either within the framework of joint application or the clean development mechanism, or even more within the framework of a widened negotiable permits market.

However, these results assume that the emission permits market operates with zero transaction costs and perfectly (no collusion, perfect information, zero cost of control and no pollution without rights).

A simulation made using the IEPE POLES model gives the following results

Country	2010 Reference (MtC)	Kyoto 2010 (MtC)	Kyoto reduction (MtC)	Kyoto/ Reference (%)	Marginal cost ($/tC)	Total cost (M$)	Effort % (% GNP)
United States	1 745	1 243	502	29	149	31 975	0.36
Canada	142	110	32	23	174	2 274	0.28
European Union	1 026	822	204	20	165	14 325	0.17
ex-USSR *	512	802	- 293	0	0	0	0
Japan	347	279	68	20	203	5 742	0.18
Total appendix B	4 182	3 618	564	13.5	-	56 419	0.23
World	8 345	7 748	564	-	-	56 419	0.11

** for the ex-USSR, the global predicted emissions are less than the commitments made by the countries in the region (Russia, Ukraine, Baltic Countries) in the Kyoto conference. The difference is a right to emit (hot air) that can be exported.*
Source : P. Criqui and L. Viguier

Thus, the total cost of achieving the Kyoto targets for appendix B countries, in other words a reduction of 564 millions tonnes of carbon compared with the reference scenario is $ 56.419 billions if there is no cooperation. Setting up a flexibility mechanism (Joint Action or emission permits market) can reduce this cost. With the joint action, a country that has made a commitment to reduce emissions, can finance a reduction operation in a country in which the unit cost is not as high as in its own country. The simulation shows that the marginal cost of achieving the Kyoto target if there is no flexibility would be about US$ 156/tonne of carbon for OECD countries, whereas the same cost would be US$ 107/tonne of carbon considering all Appendix B countries (OECD and transition countries) if the joint application is set up. This would induce a saving of the order of 16 billions dollars.

If a negotiable permits market is extended to all countries that made quantitative commitments in Kyoto (appendix B), the results of the POLES model indicate a marginal cost (therefore a price of the permit) of US $ 63 per tonne of carbon. The volume of exchanges would be of the order of 408 MtC (million tonnes of carbon). Permits would be sold by transition countries and purchased in OECD countries for a total amount of 26 billions dollars (408 Mt of carbon at $ 63 per tonne). Savings made by OECD countries compared with the reference solution without any cooperation would be $ 17 billions, savings made by transition countries would be $ 22 billions (income from the sale of permits ($ 26 billions) minus the costs of reducing emissions, estimated at $ 4 billions).

Extending the negotiable permits market to all countries in the world could significantly reduce the marginal cost, and therefore the price of the permit : $ US 21 per tonne of carbon compared with $ 63 in the previous case. At this price, about half of the commitments made by OECD countries would be achieved by purchases of permits from transition countries and half by purchases from countries without any constraints (developing countries). The total cost of achieving the Kyoto objectives would be much lower : $ 6 billions compared with $ 17 billions if aid is reserved exclusively for appendix B countries, and $ 56 billions if there is no rights market.

2 – Electricity generation : what value for external factors?

Since the 1980s, the problem of environmental external factors has been forcefully imposed on the electricity generation sector. One of the first empirical studies to estimate damage caused by electricity generation was carried out by Hohmeyer in Germany in 1988. This study had a large impact since it suggested that if external costs were made internal, renewable energies could be more competitive than coal-fired or nuclear power stations for the production of each kWh. The approach was intended to be « global » and considered impacts on health, harvests, jobs, etc. Admittedly, the assumptions were debatable since the author arbitrarily assigned one third of all atmospheric pollution in Germany to coal-fired power stations ; he also assumed that any accident in a nuclear power station would have the same effects as were observed in Chernobyl, etc. This « top down » approach was progressively replaced by more modest « bottom-up » type technical-economic approaches, carried out starting from 1991 under the sponsorship of the United States Department of Energy and of the European Commission.

It was not until Ottinger's work (1990) that a procedure to internalise environmental costs related to the generation of electricity emerged in the United States. Electricity generation companies in the States of New York, California, Massachusetts, Nevada, Oregon and Wisconsin made efforts to integrate these costs. They use the logic of adders, in other words additional environment costs added to direct costs. In 1993, 23 Regulation Commissions (PUC) obliged electricity companies to integrate these costs when selecting their new investments. But after 1993, the trend in the United States reversed to a certain extent, for three series of reasons :

– the difficulty encountered by the regulation authorities in obtaining evaluations that were not contested ;

- the internalisation procedures used were criticised due to the perverse effects that they caused. The obligation imposed on electricity companies to select new investments based on the social costs (private cost + environmental cost) encouraged many companies to delay construction of new equipment and extend the life of older and more polluting equipment ;
- the organisational framework within which American regulation authorities created internalisation is currently being modified. Opening up of networks, deregulation (which has been accelerating at federal level since 1988) has hindered taking into account external factors : intervention is no longer popular, and increased competition between producers should normally encourage electricity companies to select high performance equipment with low private and social costs.

In Europe, there is no doubt that the « ExternE » study performed by the European Commission (in 1995 and updated in 1997-1998) is the most serious reference in terms of external factors associated with electricity generation. Methodologically, the selected approach is as follows :

- the ***first step*** quantifies physical phenomena related to the construction and operation of an electrical power station (or group of power stations) ;
- the ***second step*** evaluates the environmental impacts of various risks and possible releases, in a physical perspective including diseases, accidents, death, effects on the food chain, harvests, the use of space, greenhouse effect, etc. These impacts are evaluated in probabilistic terms in the short, medium and long terms ;
- the ***third step*** converts these physical evaluations (number of deaths, working days lost, etc.) into monetary estimates. Obviously, this requires many assumptions about the price of human life, the value of space, the value of lost harvests or destroyed countryside. A decision also needs to be made about the discount value to be used, in other words the rate of social preference for the present.

Since local environmental damage is specific to a particular site, it is important to find a site representative of the electrical power stations being considered. For fossil fuel options, examples were taken in Germany and in the United Kingdom (coal, fuel oil, gas). France was used as the example used for the nuclear option. For renewable energies (wind-powered, biomass and hydroelectric), examples were taken in the United Kingdom and in Norway. In general, the results show very large differences depending on the site and technologies used for each option. The most recent version of the ExternE study is not restricted to a few typical sites and covers a wide variety of very different situations in the 15 countries in the European Union, and shows that it is difficult to select an average figure, which in any case would be meaningless considering the standard deviation around the average.

Differences can be seen in the results obtained from the ExternE study and from prior studies. The low external cost of nuclear compared with fossil fuels is due to the nature of the external factors used in all these studies.

Authors	Metho-dology	Main characteristics	Results in thousands of euros/kWh (EURO 1990)			
			Coal	**Fuel oil**	**Gas**	**Nu-clear**
OTTINGER et alii 1991	Top down	Case of United States (nuclear, coal, fuel oil, gas, hydraulic, solar, biomass). Impact on health, harvest, forest, landscape, reactor accident taken into account as well as greenhouse effect (cost of avoidance).	22 to 55	22 to 64	6 to 9	23
PEARCE et alii 1992 and 1995	Top down	Case of United Kingdom and the United States (13 subsidiaries or technologies). Impact on health, harvest, forest, landscape, reactor accident taken into account.	0.1 to 0.14	-	-	0.007 to 0.044
FRIEDRICH and VOSS 1993	Top down	Case of Germany (nuclear, coal, wind, photovoltaic). Impact on health, harvest, forest, landscape, reactor accident taken into account.	0.02 to 0.09	-	-	0.002 to 0.01
ORNLRFF 1994 Oak Ridge National Laboratory and Resources for the Future	Bottom up	Case of United States (2 sites in East and West (nuclear, coal, fuel oil, gas, hydraulic, biomass). Local and regional impact.	0.7 to 1.4			0.09 to 0.1
ROWE et alii 1995	Bottom up	Case of United States (2 sites New York - nuclear, coal, fuel oil, gas, hydraulic, biomass, wind). Local and regional impact.	3 to 5			0.09
EXTERNE 1995	Bottom up	Case of European Union (3 sites in United Kingdom, Germany) (nuclear, coal, lignite, fuel oil, gas, hydraulic, wind-powered). Local, regional and global impact (review of literature for greenhouse effect).	6 to 16 without green-house effect 20 to 30 with green-house effect	12 without green-house effect 20 to 30 with green-house effect	0.7 without green-house effect 6.7 with green-house effect	2.52 2.52
RABI et alii 1996	Bottom up	Application of ExternE (1995) to France (nuclear, coal, fuel oil, gas). Local, regional and global impact (greenhouse effect).	20 to 29	22	6.7	2.5
EXTERNE 1997	Bottom up	Case of 15 EU member countries (numerous sites). Local, regional and global impact (with new analysis for greenhouse effect). Application of YOLL methodology for the value of human life.	20 to 100 depen-ding on location	26 to 84	5 to 24	2.5 to 7.4

Source : table created from the RABL (et al) 1998 and L. Telliere-Maynat (1999)

A study by CREDEN (1999) made some suggestions about the reasons for these differences. In general, it is found that coal (and even more so lignite) and to a lesser extent fuel oil, have the highest external costs. Natural gas has significantly lower external costs. Renewable energies (wind-powered, hydroelectric) and nuclear cause the lowest external damage. For renewable energies, this is largely due to the fact that their CO_2 content is zero. Considering nuclear, we know that the figures produced do not include some costs related to the long-term management of waste, due to insufficient scientific knowledge. For example, several assumptions are made in the ExterneE study :

- the analysis is interested in priority on physical impacts on the human population (effects on health, death related to accidents and releases). The analysis includes the radiological impacts of radioactive substances released during the various stages of the fuel cycle ;
- the reliability of radionuclide dispersion models and the impact of low doses in the long term or the very long term, still raise many scientific questions. The choice of a dispersion model has a strong influence on the quality of the estimate of physical impacts.

A simple « Gauss plume » type model was used in the ExterneE study to analyse local dispersion (less than 100 km) of particles of SO2 or nitrogen oxides. To analyse regional dispersion ExterneE use « Euler grid » or « Harwell trajectory » type models, depending on the study. Dose-response functions used in all of these approaches are based on epidemiological studies that attempt to create a correlation between exposure to each pollutant and effects on the health of the exposed populations. These data consist of either chronological monitoring or longitudinal data, or data obtained from a transverse section. The results obtained will be different depending on the case.

The step in which a cost estimate is calculated is also difficult. The economic cost of a disease is usually measured by adding medical costs and the costs of lost working days. The cost of a death is even more difficult to determine. Once the idea has been accepted that a statistical value can be assigned to a human life (the value of a « statistically anonymous citizen »), then the amount of this statistical value needs to be defined. In the 1995 ExterneE study, this value is an arithmetic average of estimates based on the agreement to pay individuals to prevent the risk of a fatal accident on their place of work or in a vehicle. This avoided the approach in terms of human capital that consists of discounting and then adding all income earned by an individual, which would have meant defining a difference in the value of a life depending on the social category of the individual. The value selected was 2.6 millions Euros (about F 17 millions).

This value is considerably higher than the value that was used in France for road safety at the same time (F 3.6 millions francs). In the second ExternE (1997), it was preferred to refer to a value of a Year Of Life Loss (YOLL). The cost of the value of a human life can be estimated at 20 millions francs using this approach.

In reality, damage to public health will control the hierarchy between the different sites on which electricity is generated from fossil fuels. For example, damage to health caused by the Lauffen site in Germany is 13 times greater than damage caused on the American Knoxville site and 3 times greater than on the English West Burton site. The difference between estimates is largely due to the lack of reliability of some information and differences in the method used to evaluate them.

In the case of nuclear power, and because some external effects will not be seen until the very distant future, the monetary value of damage raises the difficult question of the choice of the value of the discount rate. Even with a low discount rate of the order of 3 %, damage of 1 Franc 100 years in the future would only be worth 5 centimes today. The ExternE teams got around this difficulty by using three different rates, namely 0 %, 3 % and 10 %. Thus, the external cost of nuclear power estimated at 2.5 millions Euro/kWh with no discount would be equal to 0.1 million Euro for a 3 % discount rate or 0.05 million Euro for a 10 % discount rate. The cost of production of a nuclear kWh is of the order of 25 millions Euro, consequently, the external cost would be equal to about 7 % of the « *private* » cost without discounting, compared with 0.3 % for a discount rate of 3 %. This choice is important since it modifies the complete cost structure.

The final estimates of external costs available in the literature must be used with a great deal of caution. External factors related to conventional thermal facilities (gas, coal and fuel oil) give an order of magnitude and are obviously very sensitive to the price of coal used in the study. But especially, there is still not enough information about the external cost for the nuclear cycle to be able to reliably include all external factors in this option. A least social cost planning would not make very much difference to the structure of generating facilities in France to the extent that, with currently estimated figures, the relative place of each option would be the same as when it is obtained by calculating the « private » cost price. However, the competitiveness of equipment being developed (combined cycles with gas and nuclear, during the 2015-2020 period) could be marginally modify. Introducing external factors does not make it possible to say that nuclear has an advantage since only part of the external costs have been estimated.

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Appendix 8

The choice of a discount rate

The choice of a discount rate to select private or public investments has been the subject of long debates between economists for more than a century, more precisely since Böhm-Bawerk first proposed an answer in 1887. Should the future be depreciated (by discounting income and expenses that will happen tomorrow) or should amounts of money available at different moments in time be added without discounting them ? If it is decided to discount, should a single rate be used regardless of the decision to be made, or should rates be differentiated depending on the nature of the decisions ? Should the rate be kept constant in time, or should it be varied depending on the period selected ? What rate should be chosen ? The real interest rate of financial markets, or the growth rate of the economy ? All these questions form part of difficult questions asked by decision makers responsible for making public choices in many different contexts such as the Soviet Revolution, or drawing up French plans to implement projects financed by the World Bank in developing countries. Two types of arguments are frequently put forward :

- not discounting (therefore choosing a zero discount rate) on the grounds that the interests of future generations would be « crushed » if the future is depreciated is economically debatable since there is a « pure preference for the present » ;

- discounting (and selecting a strongly positive rate) could cause arbitration in favour of present generations to the detriment of the interests of future generations [1]. This is an ethically indefensible choice, since it is our duty to take account of the well-being of future generations, particularly when choices made today will have serious consequences for tomorrow.

(1) Unless it is assumed that there is a very strong inter-generation altruism. As shown by Claude Henry, legacies from one generation to the next can more than compensate for the future being crushed due to discounting at a positive rate.

Faced with this lack of consensus, the public decision maker still has to decide upon a solution from the many alternatives available to him in economic theory. Therefore, this choice will necessarily seem arbitrary at any given moment. Before justifying the choice that we made, we thought it was important to summarise the current state of the debate on this question.

1- The current state of the debate

Impatience and wealth effect

Böhm-Bawerk put forward two reasons for discounting the future ; the first is a pure preference for the present. Economic agents are "impatient" and prefer to have the same amount of money today rather than tomorrow. This point of view has led to many controversies and authors such as Pigou, Ramsey and Koopmans have disputed this view of the matter ; the second reason is related to the « wealth effect ». Future generations will have better living conditions than us. Consequently, an investment that produces one unit of goods in the future in exchange for one unit of goods in the present would be unacceptable. Growth of the utility of the future generation would be more than compensated by the loss of the utility of the present generation, making the investment inefficient, if not unfair (see C. Gollier). This view of the matter was supported by W. Cline who proposed to use a discount rate composed of two elements, one representing a pure preference for the present, and the other representing a wealth effect. For example, if it is decided to use a growth rate of the economy per head of the order of 2 to 4 % and if the impatience argument is added (rate for pure preference for the present about 2 %), the result is a discount rate of between 4 and 6 % (in real terms) in other words excluding monetary depreciation). On the other end, K. Arrow suggested a rate of 4 to 5 % (1 % for pure preference and 3 to 4 % for the wealth effect).

Financial constraints

Some authors point out that financial constraints also need to be considered, and that there is a shortage of capital, even when considering two different periods. They propose to use the real interest rate determined from the financial market which, when markets are perfect (perfect information, no transaction costs, etc.) determines the optimum allocation of available savings in time. For example, we could consider the long-term interest rate of government bonds. But this choice forgets that financial markets are partitioned and are not perfect (which explains that several rates coexist). And especially, it forgets that there are no financial assets with a life as long as the expected effects of some investment choices. For example, the management of nuclear waste will be necessary for several thousand years, whereas government bonds rarely go beyond thirty years. Moreover, as mentioned by C. Gollier « even assuming that interest rates are available for very long periods, they will be biased by the existence of transaction costs, by asymmetric information, liquidity constraints and varying taxes on income from capital ».

Risks and uncertainties in the short term

One specific problem arises when reasoning in the very-long term in a context with large uncertainties. Firstly, it is necessary to consider general aversion to risks of employees, but also major uncertainties that affect any decision whenever several generations are concerned (case of the greenhouse effect or the management of nuclear waste). In this case, caution suggests that the discount rate should be reduced. The effect of this reduction is to encourage investments to prevent risks (since the expected future benefits are estimated for a case in which the discount rate would be high). For example, Kimball and Gollier have shown that uncertainty about economic growth (in the very long term) should make us wanting to reduce the discount rate « if the third derivative of the utility function of agents is positive ». We refer to « positive caution » which means making more efforts now to prevent risks for future generations. Assuming a decreasing relative aversion, it can be demonstrated that the discount rate is a decreasing function of the selected time period. Faced with very long-term risks, authors such as Faber and Hemmersbaugh suggest a rate that does not exceed the long-term growth rate of the economy (therefore of the order of 2 to 4 % in real terms). Others such as Harvey propose a variable discount rate in the following form

a (t) = b/(b + t) where b is a positive constant and t is the time.

Other authors such as Norgaard and Howarth or Daly refuse to discount and propose that a zero rate should be used whenever management of environmental resources is involved.

Therefore, there is no consensus among economists about the appropriate discount rate when public choices involve future generations, and yet it is essential to choose a rate. Not discounting at all is also a choice. Therefore any decision at this level will be arbitrary, which does not mean that it is not based on justified arguments, but that the final choice will be a « political » choice.

2 – What discount rate should be chosen ?

The answer is not easy and economic theory suggests many methods but no solution. In the case in which we are concerned (electricity generation, and more specifically nuclear generation), the influence of the discount rate is extremely complex due to the very unusual costs calendar (differential costs in the short term (capital investment), followed by dismantling, and due to the calendar of benefits depending on whether an open or closed cycle is selected or depending on the life time of power stations.

Production of electricity from nuclear plants generates a large number of effects on the well being of present and future generations. Therefore, these effects have to be made comparable before an arbitration can be made. As a first approximation, these investments have a cost for the present generation ; the construction of power stations, research and development, etc. They also have advantages, or wealth effects, for future generations that will use the existing installations and will benefit from the fruits of economic growth and accumulation of energy technologies generated by the generations who preceded them. Furthermore, these investments can generate positive induced effects for all present and future generations, since, they can indirectly contribute to resorption (or attenuation) of macroeconomic type unbalances ; reduction of external deficits, increased employment.

However, these investments can also have induced negative effects that can be very important to the well being of future generations. These future generations will have to pay costs of dismantling (or renovation) of the power stations and management of radioactive waste, some of which will have a very long life. They will also have to pay for the environmental consequences (risks of nuclear accidents and proliferation of radioactive waste) caused by the generation of electricity from which they will not necessarily benefit.

Consequently, the debate about the choice of a discount rate can be summarised by the manner in which the decision maker measures or estimates the magnitude of these two types of opposing effects or, in other words, the manner in which the decision maker weights these effects in his present day evaluation in order to make « fair » inter-generation choices. If he decides to use a high discount rate, he arbitrarily makes his decision that favours the present generation, and thereby considers that the « wealth » effects that will benefit future generations are more important than the negative effects that they will be imposed on them. Conversely, if he decides to use a low discount rate, he favours future generations to the detriment of the present generation. In this case, he considers that the consequences suffered by the future generations must not be underestimated, even though the present generation supports the initial investment costs and generates « wealth » effects and beneficial external factors for future generations.

Faced with this type of difficult arbitration, what discount rate should be used by the public decision maker to evaluate scenarios for the different electricity generation options ?

To start with, the decision maker has an excellent reference point, which is the rate of return on long-term capital. Considering the time span of the scenarios (50 years) and the fact that investments made by the « ex » public monopolies are increasingly being financed by financial market systems, the decision maker could use the long term bonds rate (30 years) as a reference rate, which is currently of the order of 6 % as a nominal value, which corresponds to a real interest rate of 4 %, assuming an average inflation of 2 % over the entire evaluation period.

However, this rate only represents the private cost effectiveness of an investment and therefore does not include all indirect effects induced by this investment. In this case the decision maker can readjust this rate upwards or downwards depending on his idea of the relative weight of positive and negative external factors related to generation of electricity.

The decision maker can thus decide that the positive effects of electricity generated by nuclear power are very important, particularly because they contribute to solving macroeconomic unbalances (an argument that was used, among others, to justify the discount rate chosen in the 9th Plan). He then adds a premium to the market interest rate to fix the discount rate by increasing the weight of the current generation. This type of reasoning is used to justify why the decision maker decided to use a discount rate as high as 8 %.

On the other end, if the public decision maker decides that negative external factors could be important for future generations, he will choose a rate less than the long-term market interest rate. He could thus decide upon any discount rate below 4 % (4, 3, 2 or 1 %, or even 0 %) based on his idea of the magnitude of the potential consequences of these external factors.

All this demonstrates the eminently political nature of the choice of the discount rate. This is why some authors qualify this choice as « meta-ethical ». No discount rate can satisfy all points of view.

A very high discount rate (for example 8 %) is ethically unacceptable when evaluating scenarios with time spans of the order of fifty years, because it would crush future values starting from the tenth year.

A discount rate of 4 %, which corresponds to the real rate of return on long-term capital (consequently that assumes that positive and negative external factors are equal and cancel each other out) is only a partial compromise. Firstly, this rate cannot take sufficient account of the interests of future generations (an even lower future rate will be necessary, for example 2 %, but this would cancel out the economic cost effectiveness of projects). Furthermore, this rate would not take sufficient account of the impatience (or pure preference for the present) of the present generation or the decision maker. Therefore, it would result in a compromise that would not be in the best interests of the present and future generations.

Finally, a discount rate lower than 4 % would give priority to the interests of future generations to the detriment of the present generation, who would nevertheless have to pay for the initial investment costs and generate wealth effects that would benefit future generations.

The conclusion is that it is impossible to be satisfied with a choice of a single discount rate to study scenarios extending over such long time spans. Consequently, a "discounting" technique needs to be defined that takes "better" account of the rational nature of economic agents (including the public decision maker), even though it may be debatable.

3 - Adoption of a two-tier discount in practice

Therefore, for the purposes of this report we will use a discounting technique that reflects economic reality for investments, and that has two objectives :

– firstly, to take account of the three realities that control the choice of the level of the discount rate ; firstly, the fact that the present generation (including the decision maker) actually has a strictly positive "pure" preference for the present, secondly that it generates wealth effects, and thirdly that it generates technological growth that can be beneficial for future generations ;

– secondly, to fairly strongly weight the well-being of future generations, in order to avoid underestimating the negative consequences that they may suffer.

In doing this, we have adopted the breakdown of the discount rate proposed by Böhm-Bawerk and reused by Cline, formally expressed as follows :

Discount rate = "pure preference for the present" rate + wealth effect

The wealth effect is equal to the product of an elasticity of the marginal utility of consumption (assumed to be equal to 1.5) and a growth rate in the income per head (anticipated at 2 %), namely 3 % over the period.

Thus, assuming an average annual "pure preference for the present" rate equal to 3 %, the resulting discount rate obtained is 6 %.

However, the "pure preference for the present" rate used in the definition of the discount rate only reflects the impatience of the decision maker (who cannot remain indefinitely in power) or the present generation who has a limited life. Consequently, we make a distinction between ***two phases in discounting :***

- a ***first phase*** which implicitly includes the decision maker's preference for the present and that covers about 30 years, in other words the average life of a decision maker in "power" or the life of a generation. The ***discount rate chosen for this period (2000-2030) is therefore 6 % ;***

- a ***second phase***, after 30 years in which the impatience is excluded and in which the induced wealth effect is no longer included. Furthermore, this allows us to implicitly integrate the well being of future generations in the evaluation that we make today. ***The discount rate chosen for the second period (2030-2050 and beyond) is then 3 %.***

Therefore, we chose to use double discounting, 6 % between 2000 and 2030 and 3 % over the time span of the scenarios, in order to satisfy the two criteria defined above. Although this method is debatable, it gives a better compromise (since it takes account of individual preferences) in the difficult exercise of discounting over the long term. The discount rate for time spans this long cannot be uniform.

For example, the following table compares a value of 100 Francs in different years discounted using this method with the corresponding value obtained using a constant rate of 4 % :

	2000	2010	2020	2030	2040	2050
6 %/3 %	100 FF	55.84	31.18	17.41	12.96	09.64
4 %	100 FF	67.56	45.64	30.83	20.83	14.07

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Appendix 9

Insurance for civilian nuclear risks

The Chernobyl accident that occurred on April 26, 1986 raised many discussions about the insurability of nuclear risks. The July 22, 1987 law attempted to consolidate the existing system. The following sites are defined as having the potential to cause a "major nuclear risk" :

– a nuclear reactor with a thermal power greater than 10 MWe ;
– a processing plant for irradiated nuclear fuel ;
– a separation plant for nuclear fuel isotopes ;
– a nuclear fuel chemical conversion plant ;
– a nuclear fuel fabrication plant.

The magnitude of the nuclear risk showed up the need for appropriate legislation for reparation and compensation as early as the 1950s. This legislation, unlike common law, was necessarily built up within an international framework due to the transnational nature of the nuclear risk. Under the auspices of the OECD, the Paris Convention (considered as being the foundation convention) was signed on July 29, 1960, and the Brussels convention was signed on January 31, 1963 with an additional protocol on November 16, 1982. Two laws (October 30, 1968 and June 16, 1990) were voted in France as a result of these conventions.

The special system [1] for nuclear insurance is based on the following five principles :

– objective liability to prevent the difficulties of searching for a fault ;
– direct liability of the operator of the nuclear installation, to avoid searching for who is liable ;
– liability limited in amount and in time, so that it remains supportable and insurable ;

(1) H. Pac « Droit et politique nucléaires » (Nuclear Law and policy) PUF (1994).

- obligation for a financial guarantee, so that victims can be certain that they will receive compensation ;
- particular rules about the competence of courts and execution of judgements, to make this compensation as easy as possible.

Thus, liability is an "objective" liability in which the victim is not obliged to demonstrate a fault, but solely to demonstrate a causal relation between the nuclear accident and the damage suffered. It is a "directed" liability to the extent that the operator of the installation is solely responsible. The operator cannot claim an act of god except in cases of armed conflicts, civil war or insurrection. It should be noted that if a nuclear accident occurs during the transport of nuclear substances, the operator of the original nuclear installation or the installation to which the substances are being transported is fully responsible for the damage, and not the transporter.

But this insurance is only partial to the extent that is limited in its amount (600 millions Francs at the moment in France) and in time (the period during which compensation can be requested is currently fixed at 10 years). Since the liability is objective (therefore with no fault) and directed, the legislator considers that it would be impossible to impose an unlimited liability on the operator [1]. These directed objective liability principles have been reused in conventions about oil pollution to the sea.

But it is planned that the State can substitute itself for all or some of the insurance and that the State will pay reparations if the insurance company or the operator are unable to do so. The State is thus a "last recourse insurer". Furthermore, in France it also compensates victims beyond the amount of the operator's liability up to an amount of 1 500 millions Francs. Beyond this amount and up to 2 520 millions Francs, reparation will be financed from an inter-state fund set up by the parties participating in the Brussels Convention.

Therefore, the State guarantees the liability of the nuclear operator and substitutes for the operator if he is unable to pay. The State pays for some risks itself, above a certain ceiling but up to a maximum limit. This is a clear sign that "nuclear energy is a field in which the liability of the State is based mainly on the concept of an exceptional risk to the population, due to the exercise of activities in the public interest, or national solidarity" (H. Pac p. 179) [2]. The

(1) The United States was the first country to introduce the principle of limited liability in the 1957 Price Anderson Act.
(2) H.Pac « Nuclear law and policy» PUF 1994.

State could even be held responsible due to its authorisation for operation, or its failure to prohibit it.

The nuclear operator (EDF, CEA, COGEMA) can take out three types of insurance policies to satisfy the compulsory nature of legal provisions in force :

- a nuclear operator civil liability to cover accidents occurring in his installation ;
- a civil liability for weapons and machinery (for the CEA only) ;
- a civil nuclear transport liability to cover accidents that occur during the transport of radioactive substances.

French operators take out an insurance policy with a group of insurance companies (Assuratome). Annual premiums are of the order of F 55 millions. But it should be noted that EDF has provisioned 400 millions to cover its proportional civil liability and only buys insurance for the remaining F 200 millions. Discussions are currently under way to increase the maximum liability of operators (and therefore premiums) that would increase from F 600 millions to F 3 500 millions. But nothing has yet been decided. It should be noted that the ceiling of the operator's liability in France is significantly lower than it is at the moment in other industrial countries with nuclear power stations.

Furthermore, nuclear operators have chosen to take out a "Civilian nuclear operator liability", the end purpose of which is to handle "conventional" and "nuclear" damage, to insure either the industrial facilities or the compensation consequences of design and engineering services and the manufacture and/or sale of facilities and equipment. Premiums paid each year to cover this liability are significantly higher than premiums for civil liability ; F 20 millions for the CEA, F 57 millions for COGEMA compared with F 8 and 6 millions respectively.

Considering that the amount of premiums paid by EDF is F 42 millions per year for effective coverage (apart from provisioning) of F 200 millions (for 58 reactors), it can be assumed that the maximum amount of premiums to be paid for a coverage of F 2 500 millions (the maximum amount set down in the Brussels Convention) should be of the order of F 530 millions per year for French power plants, which is an order of magnitude of F 10 millions per year per reactor.

1 – In the United Kingdom

The compensation logic is the same as in France, since the United Kingdom has signed the Brussels Convention. The first phase (which involves the operator) has a ceiling equal to £ 140 millions (or about F 1 500 millions), which is significantly higher than in France. The ceiling for the second phase that concerns the State is £ 175 millions, leaving £ 35 millions to be paid for by the State. The Brussels Convention is applied for higher amounts, in other words an association of States (with a ceiling of £ 250 millions). But the British State can then pay more if decided by Parliament (following a proposal by the Ministry of Energy). It should be noted that the State can then initiate proceedings against the operator to request compensation if the accident was due to serious negligence by the operator).

2 – In the United States

The founding text is the "Price-Anderson Act" text adopted in 1957 and revised regularly since (this document is actually an amendment to the legislation on nuclear energy included in the 1954 " Atomic Energy Act"). The initial idea was to enable the development of nuclear energy by limiting the financial liability of operators, and to guarantee additional public funds in the case of an accident. The maximum available coverage from private insurance companies was initially $ 60 millions, and the maximum amount of the additional public funds was set to $ 500 millions. In 1967, and then in 1975 and in 1988 the Price-Anderson Act was extended and ceilings were increased. It will be renewed in 2002. A two-level system for the "private insurance" part was introduced in 1975.

The system currently in force (ceilings adjusted in 1998) is as follows :

– the operator is liable for the first phase of $ 200 millions (about F 1 400 millions) (through his insurance) ;
– if this coverage is insufficient, operators of all reactors under license (at the moment 108 including 105 in operation and 5 shutdown but which are still managing used fuel) are asked to contribute to a pool for a maximum amount of $ 88 millions per reactor, giving a total of $ 9 500 millions. This increases the ceiling for the second phase to $ 9 700 millions (or about F 69 000 millions) ;
– beyond this second ceiling, Congress will decide if additional compensation should be made, and who will pay for it.

In practice, operators are insured by American Nuclear Insurers, a group of about sixty insurance companies. The Nuclear Regulatory Commission (NRC) is responsible for the classification of a nuclear accident as such. Claimants can then be compensated provided that they can demonstrate 1) the existence of damage (bodily or equipment) 2) the relation between the damage and radioactive contamination. This is the same concept adopted in other countries (including France) ; liability directed to the operator, and objective liability of the operator (a link has to be demonstrated between the damage and the accident, but it is not necessary to prove fault). However, the material nature of the damage and its relation to the radioactive contamination do have to be proven before compensation can be claimed.

3 – In Japan

Within the framework of the 1961 law, the nuclear operator is obliged to pay compensation for damage caused by a nuclear accident, ***without restriction***. He is also obliged to take out insurance for which the maximum compensation is determined by the law depending on the type of operation and the type of installation. For example, the maximum compensation paid by the insurance company may be 60 billions yens (about F 4 200 millions) in the case of an accident in a nuclear power plant with a thermal power exceeding 10 MWe, or in the case of an accident in a reprocessing plant. It is limited to 12 billion yens (about F 840 millions) for an accident that occurs in a power plant smaller than 10 MWe, in a nuclear waste installation, or during transport of nuclear materials or waste. It has a ceiling of 2 billions yens (140 millions) in other cases covered by the law. The insurance premium paid by all companies concerned was 24 billions yens (F 1 680 millions) in 1998. An insurer pool was created in 1960 composed of 43 insurance companies. Other compensation ranges are currently being studied, concerning ultimate disposal and dismantling of a reactor or nuclear fusion reactions.

The law on compensation for nuclear accidents was applied and compensation was paid in Japan for the first time during the criticality accident at the JCO uranium conversion plant in Tokai Mura in September 1999. The compensation paid by the insurer pool companies was 1 billion yens, or about F 70 millions, but the total compensation paid by JCO was 11.6 billions yens (about F 810 millions), applicable to 6 540 files. Therefore, the operator has a considerable liability in Japan in the case of a nuclear accident because a priori there is no limit.

However, it should be noted that if the amount of compensation exceeds the maximum compensation payable by the insurance company or the company responsible is financially incapable of paying, a subsidy will be assigned by the Government after a debate in Parliament (new clause planned in the year 2000). When an accident is caused by a natural catastrophe or social upheaval, the Government will pay for compensation instead of the company concerned. Therefore, the State does act as the last recourse but its action is much more restricted than in Europe since a priori the operator is responsible for compensation.

The system currently in force in Germany and in Sweden is similar to the French system but the operator is responsible for compensation at a ceiling significantly higher than the value in France (see table below). Therefore, the manner in which the nuclear risk is insured is particular because the State may pay additional compensation after the operator has paid the maximum amount of his liability. Some consider this to be a form of potential subsidy, others that it is an obligation of the State.

	France	**Germany**	**U.K.**	**Sweden**	**United States**	**Japan**
Phase 1	Operator 600 millions	Operator 800 millions	Operator 1 500 millions	Operator 1 500 millions	Operator 1 400 millions	Operator A priori no limit
Phase 2	State 600 to 1500 millions	Pool between operators 800 to 2000 millions	State 1500 to 1800 millions	Pool of States (Brussels Convention) 1500 to 2500 millions	Pool of operators 1400 to 69000 millions	But ceiling for insurance companies equal to 140 to 4200 millions depending on the case
Phase 3	Pool of States (Brussels Convention) 1500 to 2520 millions	State (or pool of States)	Pool of States 1800 to 2520 millions	State under certain conditions	Federal State (after decision by congress)	State (under certain conditions) (if the operator is unable to pay)

Glossary

Actinides: Group of chemical elements heavier than actinium (atomic number 89). Four actinides exist in the native state: actinium (89), thorium (90), protactinium (91) and uranium (92).

Minor actinides: Elements of atomic numbers between 89 and 103 on the Mendeleiev classification scale. The major actinides are uranium and plutonium. The other actinides are referred to as minor actinides and comprise in particular the americium, neptunium and curium formed in the spent fuels.

NEA: Nuclear Energy Agency. Set up in 1957, it belongs to the OECD and is a forum for legal, technical and scientific co-operation between States concerning the production and utilisation of nuclear energy. The NEA has no powers of control.

IAEA: International Atomic Energy Agency. An intergovernmental organisation set up in 1957, which belongs to the United Nations. Its role is to favour and promote the peaceful use of atomic energy throughout the world.

Alpha: The particles that compose alpha radiation are helium 4 nuclei (2 neutrons + 2 protons) that are highly ionising but have a low power of penetration. A single sheet of paper can stop their propagation (symbol α).

ANDRA: French national agency for radioactive waste management (Agence Nationale des Déchets Radioactifs), a public institution with an industrial and commercial vocation, in charge of the management and disposal of solid radioactive waste.

Atom: The basic component of matter. It is composed of a nucleus (neutrons + protons) around which revolve electrons.

Control rods: Boron or cadmium tubes inserted vertically into the reactor core and designed, through neutron absorption, to control the reaction and therefore the power produced (also called « rod cluster control assembly »).

Containment barriers: A set of sealed devices intercalated between the radiation sources (fission products present in the reactor) and the outside environment. Those protections are successively composed of :

- the metal tube containing the nuclear fuel (zircalloy tube),
- the steel vessel containing the reactor core and the cooling system,
- the reactor building (sealed structure in reinforced concrete)

Beta: The particles composing beta radiation are negative or positive charge electrons. A shield of a few meters of air or a simple sheet of aluminium can stop them (symbol β).

CEA: Commissariat à l'Energie Atomique (Atomic Energy Commission). It is placed under the authority of the Prime Minister, and is in charge of carrying out research to promote the use of nuclear power in science, industry, and for national defence.

Cesium: A rare and toxic metal whose characteristics are comparable to those of potassium. Its isotope, cesium 137, is a radioactive fission product that can be found in the various circuits of the nuclear area.

Reactor loading: Loading of a nuclear fuel into the reactor. In pressurised water reactors (PWR), that operation takes place with the reactor shut down and the vessel open; it is usually carried out once a year. The fuel remains three or four years in a reactor. Therefore, only one third or one quarter will be renewed each year. New assemblies are then placed in the peripheral areas of the core.

COGEMA: General Company of Nuclear Substances (Compagnie Générale des Matières Nucléaires). A subsidiary of the AEC, its activities cover the overall nuclear fuel cycle (mining operations, conversion, enrichment, manufacturing, reprocessing of irradiated fuels).

Nuclear fuel: The fissile matter used in the reactor to develop a chain nuclear reaction. The new fuel in a pressurised water reactor is composed of uranium monoxide enriched with uranium 235 (between 3 and 4 %).

Containment: A protective device that consists in confining the radioactive substances inside a specific closed area (see Containment Barriers).

Fuel cycle: All the steps followed by the fissile fuel: ore extraction, fuel elaboration and conditioning, utilisation in a reactor, reprocessing and later recycling.

Reactor unloading: Operations consisting in withdrawing the nuclear fuel from a reactor. In pressurised water reactors (PWR) they always take place with the reactor shut down and the vessel open.

Radioactive waste: (radwaste). Radioactive substances that cannot be re-used. Originates from medical centres, laboratories or the nuclear industry.

Effluents: Liquids or gas containing radioactive substances. Their activity is reduced by appropriate devices before they are released or used.

Reactor containment or reactor building: A concrete sealed building containing the reactor vessel, the primary cooling system, the steam generators and the main auxiliaries ensuring reactor safety. During scheduled outages, a large number of people operate inside the reactor containment.

Enrichment: A process through which the fissile isotope content of an element is increased. Uranium, for example, is composed in its native state of 0.7 % of uranium 235 (fissile) and 99.3 % of uranium 238 (non-fissile). Uranium 235 becomes efficient in a PWR if its proportion is increased to approximately 3 to 4 %.

EURATOM: European Atomic Energy Community, set up in 1957. Its general task is to promote nuclear industries and the development of exchanges with other countries. One aspect of its work is nuclear substance control in nuclear plants.

Eurodif: A European plant for the enrichment of uranium using gaseous diffusion, and a provider of services to civil nuclear industries. It is located near the Tricastin plant, in the Drôme department of France. The major countries represented in EURODIF are France (majority share), Italy, Spain and Belgium.

Fertile: A nuclide is called fertile if, by capturing a neutron, it can transform into a fissile nuclide, for instance, uranium 238 which transforms into plutonium 239, is a fertile nuclide.

Fissile: A nuclide is called fissile if its nucleus is likely to undergo fission under the effect of neutrons of all energies, for instance, uranium 235.

Nuclear fission: The explosion of a heavy nucleus into two parts, resulting in the emission of neutrons, radiation and a significant release of heat.

Isotopes: Elements whose atoms have the same number of electrons and protons, but a different number of neutrons. There are, for example, three uranium isotopes: uranium 234 (92 protons, 92 electrons and 142 neutrons), uranium 235 (92 protons, 92 electrons and 143 neutrons) and uranium 238 (92 protons, 92 electrons and 146 neutrons). Approximately 325 natural isotopes and 1,200 artificial isotopes are presently known.

MOX: Mixed fuel containing uranium dioxide and plutonium dioxide (UO_2 and PuO_2).

Neutron: An electrically neutral elementary particle that composes, with protons, the atom nucleus. The neutron causes the fission reaction in the fissile nuclei and the energy released is used in nuclear reactors.

Nuclide: An atomic nucleus characterised by the number of protons and number of neutrons it contains.

Period: The radioactive period is the time necessary for a radioactive material to lose half of its radioactivity. In 2 periods, the radioactivity drops to one-quarter its initial level. In 10 periods it drops to $1/1000^{th}$ In 20 periods, it drops to approximately $1/1\,000\,000^{th}$.

Activation products: Radioelements formed by the irradiation of the fuel cladding, nozzles and other structural materials of nuclear reactors.

Plutonium: An element whose atomic number is 94. There is no isotope for plutonium in the native state. Plutonium 239, a fissile isotope, is produced by nuclear reactors using uranium 238. Its handling requires drastic precautionary measures due to its chemical toxicity and the dangers presented by its alpha rays. Symbol Pu.

Fission products: Fragments of heavy nuclei produced by nuclear fission or the later radioactive disintegration of the elements formed by this process.

Radioactive: Possessing radioactivity, i.e. spontaneously emitting alpha « α », beta « β » particles or gamma « γ » radiation. More generally, that term refers to the emission of radiations resulting from the fission or disintegration of an unstable element.

Radioelement: Any radioactive chemical substance. Only a small number of radioelements exist in the native state : a few heavy elements such as thorium, uranium, radium, etc. and a few light elements such as carbon 14, Krypton 40. The other radioelements (there are more than 1,500) are created artificially in laboratories for medical purposes or in nuclear reactors in the form of fission products.

Nuclear reaction: A process resulting in the modification of the structure of one or several atom nuclei. The transmutation can either be spontaneous, i.e. it requires no intervention external to the nucleus, or caused by the collision of other nuclei or free particles. The nuclear reaction is always accompanied by a release of heat. Fusion occurs when the impact of an isolated neutron divides a heavy nucleus into two sensibly equal parts and releases neutrons into space. There is fusion when two light nuclei unite to form one heavier nucleus.

Chain reaction: A series of nuclear fissions during which the neutrons released cause new fissions, which in turn generate the expulsion of neutrons towards target nuclei, and so on.

Transmutation: In the case of highly active radioactive waste, the operation of transforming long-life radionuclides into stable nuclei, eventually into distinctly shorter lived substances.

Transuranium elements: Group of chemical elements heavier than uranium (atomic number 92). The major transuranium elements are neptunium (93), plutonium (94), americium (95), curium (96). They also belong to the actinides group, neptunium, americium and curium are also referred to as « minor actinides » for they are contained in a lesser quantity than plutonium in the spent fuels.

Tritium: Isotope of hydrogen, emitting beta radiation, present in the effluents of water reactors. Symbol : H3.

Uranium: In the native state, uranium comes in the form of a mixture of three major isotopes:

- uranium 238, fertile in a proportion of 99.28 %;

- uranium 235, fissile in a proportion of 0.71 %;
- uranium 234.

Uranium 235 is the only natural fissile isotope, a quality that explains its utilisation as an energy source. Symbol U.

Long life: A radioelement is considered "long-life" when its period is more than 30 years and less than 1 billion years. Under 30 years it is considered a short-life radioelement. If its life is longer than one billion years, it is considered to be "stable".

Others

Excerpt from the « Bataille » law (on radioactive waste storage and management) passed in December 1991

« The National Assembly and the Senate adopted.
The President of the Republic proclaimed the law containing the following:

Article 1 – The management of highly active long-life radioactive waste must be assured with respect for the protection of nature, the environment and health and with due regard for the rights of future generations.

Article 2 – It is inserted after article 3 of the law n° 76-663 passed on July 19th 1976, relative to installations classified for environmental protection, is an article 3-1, drafted as follows :

« Art. 2.1 – The underground storage in deep geological layers of dangerous products of any kind whatsoever requires a permit issued by the administration. That permit can be granted or prolonged for a limited period only and conditions may therefore be stipulated regarding reversibility of the storage. The products must be withdrawn from storage upon expiration of the permit.

« The applicable conditions and guarantees required for certain permits to be granted or prolonged for an unlimited duration, by waiver of the terms of the previous sub-paragraph, shall be defined by law at a later date ».

Art. 3 – Even if reprocessing takes place on national (French) territory, the storage in France of imported radioactive waste is prohibited beyond the technical waiting periods imposed by reprocessing.

Art. 4 – Each year, the Government submits to the Parliament a progress report on research into the management of highly active long-life radioactive waste and of work being performed simultaneously to:

- find solutions to enable the separation and transmutation of the long-life radioactive elements present in that waste;
- study possibilities for reversible or irreversible storage in deep geological formations, by means of the construction of underground laboratories in particular;
- study processes for the conditioning and long-term surface storage of that waste.

The report also discusses the state of research and projects in progress abroad.

Upon expiration of a period not exceeding fifteen years from the date of promulgation of the law herein, the Government shall submit to Parliament a general report assessing those research projects plus, if appropriate, a bill authorising the creation of a storage facility for highly active long life radioactive waste and setting out rules on easements and other requirements relating to that facility.

Parliament submits those reports to the Parliament Office for the Evaluation of Scientific and Technological Options.

Those reports will be made available to the public ».