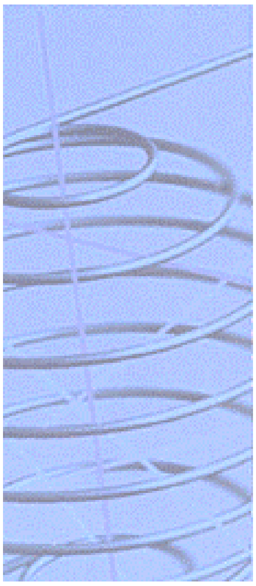
COAL OPTIONS
Evaluation of coal-based power generation in an uncertain context

Final report

UCL – CORE
UCL - TERM



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Evaluation of coal-based power generation
in an uncertain context

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September 2001

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ABBREVIATIONS

GT	Gas Turbine
STAG	STeam And Gas combined cycle
CCGT	Combined Cycle Gas Turbine
NGCC	Natural Gas Combined Cycle
IGCC	Integrated coal Gasification Combined Cycle
PC-USC	Pulverised-Coal fired plants with (Ultra) Supercritical steam Cycle
AFBC	Atmospheric Fluidised Bed coal Combustion
PFBC	Combined cycle with Pressurised Fluidised Bed coal Combustion
UCG	Underground Coal Gasification
CHP	Combined Heat and Power (cogeneration)
IPP's	Independent Power Producers
IPG's	Autoproducers

SYMBOLS

t, y	time, year
t_0	commissioning year of the plant
t_R	repowering year
n	lifetime, year
I	specific investment cost, EUR/kW
CP(t)	coal price at time t, EUR/GJ
P(t)	natural gas price at time t, EUR/GJ
P'(t)	natural gas price at time t, EUR/kWhe
$f_y[P(t)]$	probability density function of natural gas price at time t based on price information given at time y
E_y [P(t)]	mean expected value of natural gas price at time t based on price information given at time y, EUR/GJ
μ	mean expected growth, s^{-1}
σ	volatility, $s^{-1/2}$
α	trend, s^{-1}
I	discount rate
U_t	annual utilisation for year t, hours/year
FOM(t)	fixed O&M costs for year t, EUR/kW.year
VOM(t)	variable O&M costs for year t, EUR/kWh
EGC	electricity generating cost, EUR/kWh
NPV_t	net present value based on natural gas price information given at time t, EUR/kW
ROVt	real options value based on natural gas price information given at time t, EUR/kW
FV	flexibility value, EUR/kW
OC	option cost, EUR/kW

SUMMARY

The project COAL OPTIONS pursues three related objectives:

1. Improve our knowledge of the potential for innovation in fossil fuels fired power plants (coal and natural gas).
2. Improve our tackling of uncertainties and plant flexibility in plant valuation and investment decisions in an evolving context.
3. Improve our understanding of the forces driving the future choices of investment by the power companies and the effect of these choices on greenhouse gas emissions.

The project relies on standardised technical data generation and on the development of a decision investment model derived from the financial world.

Power plants considered are limited to gas-fired CCGT units and coal-fired IGCC and PC-USC units. Several technical options for each technology have been selected. Existing power plants performances have been collected. Then standard curves for techno-economic performances (full load and part load efficiency, investment cost, O&M costs) in function of the installed capacity have been deduced. Similar work has been performed for specific emissions (CO_2, NO_x, SO_2, and dust).

Evolution in the future of major technological parameters have been deduced from manufacturer publications. Corresponding evolutions of techno-economic and environmental performances have been obtained by the development of physico-chemical and thermodynamic power plant models.

A banker managing a portfolio of securities faces many uncertainties. To help him in his task, modern finance has developed many risk management tools particularly well adapted to value the return on an investment in an uncertain context (options theory). We apply that same methodology to the assessment of coal and natural gas power plants in the context of a competitive and uncertain electricity market by application of the real options theory.

The method makes it possible to tackle various uncertainties pervading the European electricity market, namely:

1. prices of fuels
2. prices of electricity
3. standards and costs relating to the polluting emissions
4. evolution of the technological performances of the power plants.

Affine jump diffusion processes were finally selected and calibrated in order to predict the stochastic behaviour of fuel prices, electricity prices and CO_2 emission permits. Evolution of technological performances was finally described by a deterministic approach (scenarios).

For plant valuation, the formalism of European options on spreads between electricity and fuel prices has been retained. The model computes the value of an investment realised at a certain date. In addition to the initial option to choose the type of power plant, one will be able to consider the option to stop or start-up the production of electricity depending on the price of electricity in market. Two numerical integration methods have been used to solve this two stochastic factors model: Monte Carlo simulation and Fourier Transform analysis.

For plant investment decision, the formalism of American options on spreads between electricity and fuel prices has been retained. In addition to above-mentioned options, one will be able to consider the option to delay the investment and consequently to find the optimal date for investment.

The method also makes it possible to give a financial value to the capability of a power plant to adapt to fluctuating conditions ("flexibility"):

1. fuel switching
2. options of repowering
3. capability to adapt to the standards of emission
4. operational flexibility.

Unfortunately, due to a lack of human resources it has not been possible to integrate these flexibility options in the model. Only limited case studies based on a simplified approach have been performed simulating competition between gas-fired and coal-fired power plants or between state-of-the-art power plants and innovative concepts.

The project is composed of two teams:

TERM, Unit of thermodynamics, UCL: technological characteristics (technical, environmental, economic, flexibility) generation for gas-fired and coal-fired power plants. Techno-economic modelling of the power plants in stationary state and potential of innovation (scenarios at the medium and long term).

CORE, Center for Operations Research and Econometrics, UCL: application of the theory of real options: treatment of uncertainties (prices of fuel, prices of electricity, CO_2 emission costs) and modelling of the plant valuation and investment decision.

Main results provided by this project are:

1. A method for techno-economic optimisation of electric power plants that make it possible to estimate the potential of innovation. This method will be transposable to other types of thermal power plants (combined heat and power systems, biomass gasification systems,…). Results consist of database and models.
2. Standard performance curves and scenarios for each technological options considered.
3. Calibration of stochastic processes (fuel prices, electricity prices and emission permits).
4. A methodology for power plants valuation and investment decision in a competitive organisation of the industry, considering a financial value for power plants flexibility's.

1 OBJECTIVES

1.1 Global issue

Consequences of the new competitive European electricity market on power plant investment decisions.

Towards a better treatment of uncertainty.

Uncertainty has reached an unprecedented level in the European electricity market: impacts of the liberalisation on power companies and on electricity prices, evolution of long-run natural gas prices, evolution of the greenhouse gases reduction commitments, evolution of emissions standards (SO_2, NOx, dust,…), performances of newly emerging technologies.
It has been recognised in the last ten years by major lenders that investments in the energy sector in general, and in the electricity sector in particular should not be driven by the simple net present value criterion. The reason is the uncertainty that normally surrounds the energy field. Interestingly enough it has long been recognised in other energy areas, and in particular in energy consuming industries that investment choices are effectively not always dictated by this criterion. Future uncertainty is in those cases too often mentioned as the reason to depart from the pure application of net present value computation. While regulated companies like power companies have, in the past, been able to pass uncertainty to their customers, this will no longer be possible in the future.

Opportunities for emerging power plant technologies?

Serious mistakes on the assessment of the possibilities of technologies can be made if the methodology does not take into account their capability to adapt to uncertainty ("flexibility"). Therefore, flexibility need to be taken into account when assessing the economic potential of alternative technologies with respect to their main competitors.

Which impact on CO_2 emissions?

Extensive use of such new investment decision methods in the power industry will probably modify the generation capacity mix and thus have an impact on CO_2 emissions dedicated to electricity generation.
Moreover, instruments introduced by public authorities mainly modify the economic and technological parameters of the relevant technologies. Their effectiveness is thus also affected by the prevailing uncertainty. The same shortcomings will thus also be found in the evaluation of their effectiveness if one restricts oneself to standard techniques that do not account for the ability of technologies to adapt to uncertainty.

1.2 Goal

Analysis of competition between fossil fuel power plants by means of the theory of real options

Limitations of greenhouse gas emission from large-scale fossil fuel-based power plants are probably a key element of a strategy towards sustainable development. The power sector is currently driven by a dash for gas that, at least partially, contributes to the desired result when substituting for less efficient coal power plants. Major characteristics of the natural gas-fired combined cycle plant are high efficiency, low investment costs, low environmental impact, short installation time and good operating flexibility. Many expect that for reasons of resource availability and/or production and transportation cost of the natural gas, this evolution will be limited in time.
In this case, whatever attitude towards nuclear energy and renewables, new investments in coal power plants will probably be considered. In comparison to other fuels, coal is characterised by important reserves and lower prices but also by much higher emissions of pollutants. Newly

emerging coal-based technologies with more efficient conversion of coal and improved environmental performances appear then as a main option to limit greenhouse gas emission with respect to conventional coal power plants: they will thus have to be considered in any strategy of the power sector to contribute to sustainable development.
In an uncertain context, are these new, less polluting but more expensive innovative coal power plants competitive in comparison to gas-fired STAG units and more conventional coal power plants? What are the capabilities to adapt to uncertainty ("flexibility") of these power plants? What are their economic values?
The theory of real options applies to power plant valuation and optimal investment decision modelling allows a more adequate treatment of uncertainty than methods based on a net present value computed over a set of scenarios. The idea of the theory is that a less flexible equipment is at a disadvantage that is not included in the standard net present value calculation. Then, this theory gives an economic value to power plants flexibility's such as fuel switching, repowering opportunities, capability to adapt to the standards of emission and operational flexibility.
This approach directly draws on the theory of financial options initiated in the celebrated work of Black-Scholes (1973). It culminated in the book of *Pindyck and Dixit (1994).* The idea was well publicised by the World Bank which first pointed out the drawbacks of using net present value calculation for assessing the relative competitiveness of equipment that have quite different characteristics of flexibility. The relevance of the theory of both financial options and real options is illustrated by the importance taken by this subject in several energy companies in the world. It is noticeable that this work has also found its way into issue of sustainable development.

1.3 Team objectives

Development of a tool taking into account uncertain facfors for the analysis of competition between coal-fired and gas-fired power plants in the mid- and long run.

1.3.1 TERM

Technological characteristics (technical, environmental, economic and flexibility) and potential for innovation (in the mid- and long-run) of coal and gas-based power plants

Specific objectives are:

1. Identification and characterisation of main coal-based and gas-based technologies
2. Performances of current power plants
3. Scenarios of evolution of these performances in future
4. Flexibility characteristics of these power plants
5. Scenarios of evolution of these performances in future
6. Case studies by integration of the data generated by TERM in the model developed by CORE

These objectives have been achieved by data collection from scientific publications, trade journals and manufacturer communications and by the development of physico-chemical / thermodynamic / techno-economic power plant models.

1.3.2 CORE

Application of the real options theory

Specific objectives are:

1. Risk factors modelling : stochastic processes selection and calibration for fuel prices, electricity prices and CO2 emission permits
2. Development of a power plant valuation model
3. Development of power plant investment decision model

2 METHODOLOGY

2.1 Gas-fired and coal-fired power plants characteristics

2.1.1 Technical options

For each technology considered (STAG, PC-USC, IGCC), several technical options have been selected and standardised according to the following classification:

Physico-chemical data
- fuel conditioning and feeding
- nature of the oxidant or the gasifying agent
- combustion / gasification conditions

Thermodynamic data
- gas turbine cycle conditions (pressure and temperature)
- steam cycle conditions (pressure and temperature)

Environmental data
- fuel gas treatment (IGCC)
- flue gas treatment (dust, NOx, SO2)
- solid and liquid residues

2.1.2 Current power plants performances

We have only considered commercial plants or demonstration plants at commercial scale (e.g. Buggenum IGCC power plants in The Netherlands). For each identified power plant, the following data have been collected and standardised (fuel composition, air and cold-end conditions,…) :

Techno-economic performances

1. Installed capacity
2. Full load and part load efficiency
3. Investment cost
4. O&M costs

On this basis, two types of **standard curves** have been achieved:

1. Effect of size for efficiency, investment cost, O&M costs
2. Part load efficiency

Environmental performances

We have only considered emission related to power plant operation. Emissions from fuel extraction, transport, power plant building and dismantling are therefore not considered, as it's the case with the LCA approach.

1. Specific CO2 emission (g/kWh)
2. Specific NOx emission (mg/kWh)
3. Specific SO2 emission (mg/kWh)
4. Specific dust emission (mg/kWh)

In this study, CO2 capture technologies in flue and fuel gases are not considered. Then, CO2 emissions are simply derived from power plant efficiency and fuel composition. In addition of these parameters, combustion/gasification conditions and flue gas treatment are used to assess NOx, SO2 and dust specific emissions.

On this basis, standard curves have been obtained:

1. Effect of size for specific emission
2. Specific emission at part load

Unfortunately, the decision model developed in the frame of this project is only able to use a small part of these results and further developments are required in order to valorise in future all this set of data.

2.1.3 Potential for innovation

Evolution of power plants performances has been obtained by the following way:

1. Evolution of major technological parameters:

   The selected parameters are only those related to the thermodynamic cycle:
   - maximal firing temperature of the gas turbine cycle
   - steam pressures and temperatures of the steam cycle

2. Performance calculation by means of these technological parameters:

   Efficiency and specific emissions are obtained from physico-chemical and thermodynamics models of the various power plants considered. Some of the thermodynamic parameters are optimised according to a techno-economic criteria (e.g. steam pressures of the steam cycle in a STAG power plant).
   Concerning the investment costs, correlations from cost engineering databases and thermoeconomics developments are used to express the cost in function of thermodynamics parameters, material used and design of the components.

3. Combining step 1 and 2 gives us various scenarios describing the time-evolution of the performance (efficiency, specific emissions, investment costs) for gas-fired and coal-fired power plants.

4. Above-mentioned thermodynamic parameters are not the only driving force for improvement of power plants performances. Scenarios also include potential technological jumps identified in the frame of this project (hot gas filtration for IGCC, sequential combustion for gas turbine,…)

5. These scenarios are compared and completed by those obtained with the *experience curve* methodology *(Wene, 2000)*. In this case, a power function between price / cost or efficiency and experience over time, i.e. cumulative production of units, installed capacity, is derived from historical data. The time-evolution of power plants performance is then obtained from market development scenario (e.g. period for doubling the cumulative production) .

These scenarios are only valid for an installed capacity range. They can be adapted by means of the standard scale laws in the case of other capacity range.

These scenarios are dedicated to be used by the decision model developed by the CORE team.

2.2 Risk analysis

Only fuel prices, electricity prices and emission permits have been analysed. For these risk factors, suitable stochastic models have been selected and calibrated in order to predict efficiently the behaviour of main risks factors.

2.2.1 Fuel prices and electricity prices uncertainty

The theory of real options was relatively poorly endowed in computational terms at the time the project started. This quickly showed up in the work as the first year of the projects revealed important difficulties. Energy prices do not follow the standard diffusion processes found in finance and extensively used in the work done at the time in real options.

The formalism of affine jump diffusion processes may present some mathematical difficulties, but it allows one to represent many of the idiosyncrasies of electricity prices. Specifically affine jump diffusion processes are quite suitable for modelling mean reversion (which is a characteristic of all energy prices) and jumps (which are particularly important in electricity but also arise in natural gas).

2.2.2 CO2 emissions mitigation uncertainty

Discussion with MIT specialist in emission trading Dr D Ellerman led us to model this uncertainty though prices of emission permits. Even though it is not certain that this policy instrument will prevail, the slow progress of the Kyoto protocol leads one to conjecture that some more structured arrangement will need to be developed and that emission permits on a global scale will emerge. Sticking to the overall methodology of real options, the problem is then to model the stochastic process that describes the evolution of the price of these permits. The idea was to fit a diffusion process with jumps at well specific periods of time. This suggestion emerged from discussion with Professor Emeritus A. Manne from Stanford University. Prof. Manne is directing the Energy Modelling Forum project on global working. The results of models run in the context of this project provide the necessary information to model this price process.

2.3 Plant valuation

The model developed gives the value of an investment realised at a certain date. The value of a plant is modelled as a strip of European options on spark spread between electricity and fuel prices (two stochastic factors model). In more usual terms, this equal to the integral, over the life of the plant, of an option on the difference between the price of electricity and the cost of fuel. In addition to the initial option to choose the type of power plant, one will be able to consider the option to stop or start-up the production of electricity depending on the price of electricity in market.
Progress on Fourier Transform analysis and Monte Carlo simulation, based on the affine jump formalism, have been written for this plant valuation process.

2.4 Investment decision model

To model the investment decision in power plants through a realistic and computable real option model, we retained the formalism of American options on differences (spread) between electricity and fuel (gas or coal) prices to do so. The payoff of this option, when exercised, is the value of the plant computed by the plant valuation model. American options on spreads are a novel problem. A program based on complementary formulation of this American option has been written. Consequently, in addition to above-mentioned options, one will be able to consider the option to delay the investment and consequently to find the optimal date for investment.

3 GAS-FIRED COMBINED CYCLE GAS TURBINE (NGCC)

3.1 Current performances

A large amount of current technical and economical data is available and has been collected from major gas turbine manufacturers and trade journals (*Gas Turbine World, 1996-2001*).

The gas turbine technology is characterised by a few number of original equipment manufacturers (OEM's) and by recent amalgamation (e.g. ABB and Alstom). At present, 4 power engineering company are covering more than 95% of gas turbines ordered in the world and about 70% of CCGT (*Tait, 1999*) : ALSTOM POWER, GE Power System, Siemens Westinghouse and Mitsubishi Heavy Industries. Gas turbine systems are provided by around 40 packagers and CCGT by around 25 packagers in the world, each packager providing some specific options or modifications from the standard OEM's design.

In order to analyse the performances of gas turbines, four category of gas turbines must be distinguished with respect to their capacity and related market application :

1. Micro (P < 1 MW), CHP application
2. Industrial (P < 50 MW), CHP application
3. Aeroderivative (derived from aircraft engines, P < 50 MW), CHP application
4. Heavy-frame (P > 50 MW), CCGT configuration, electricity production or CHP

In a simple cycle configuration, GT efficiency and specific output are mainly depending on firing temperature and pressure ratio has shown in Figure 3-1. The influence of a higher firing temperature on efficiency is in principle still positive but can in practice be limited by the cooling system required. In addition, a maximum of 1500 °C is to be considered for the firing temperature due to NOx limitation.

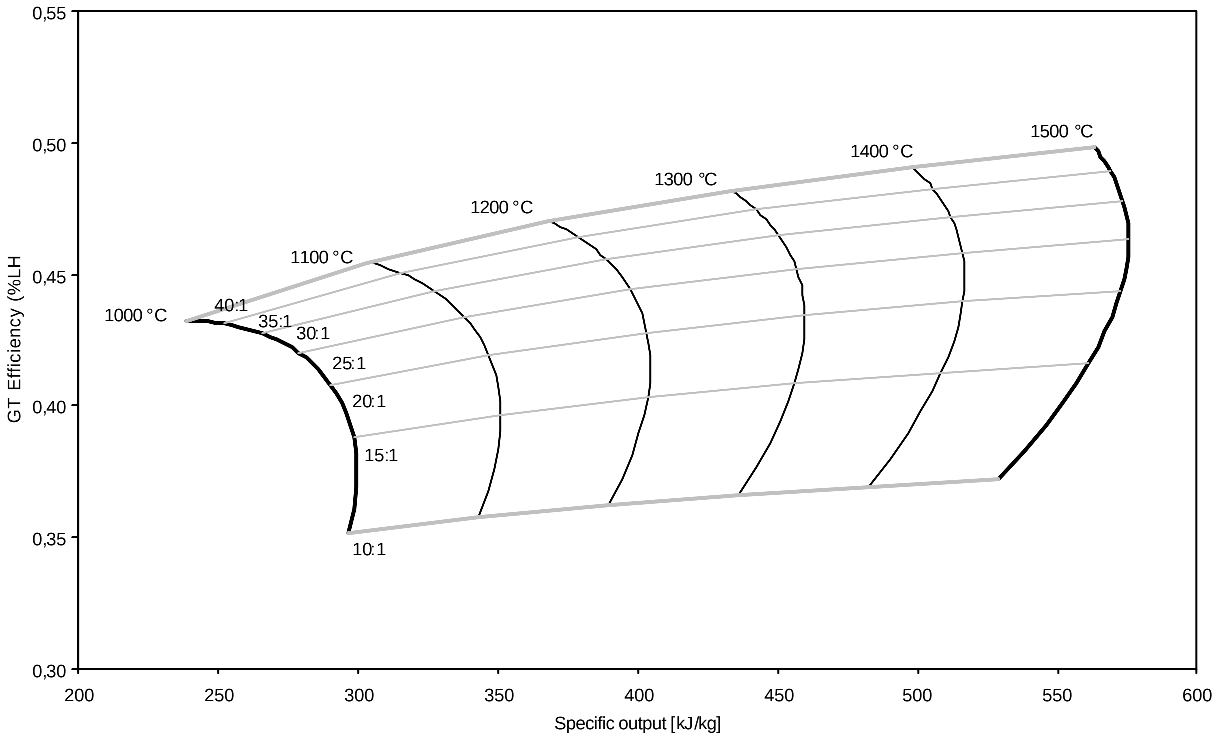

Figure 3-1 : Influence of firing temperature and pressure ratio on gas turbine performances

For combined cycle application with generally high annual utilisation, a high efficiency is required. Figure 3-2 shows that maximum combined cycle efficiency is not achieved with gas turbine designed to optimise its effiency but rather its specific output. Heavy frame gas turbine are consequently designed with lower pressure ratio than aeroderivative gas turbine (mainly designed for CHP application) leading to lower simple cycle gas turbine efficiency but higher combined cycle efficiency.

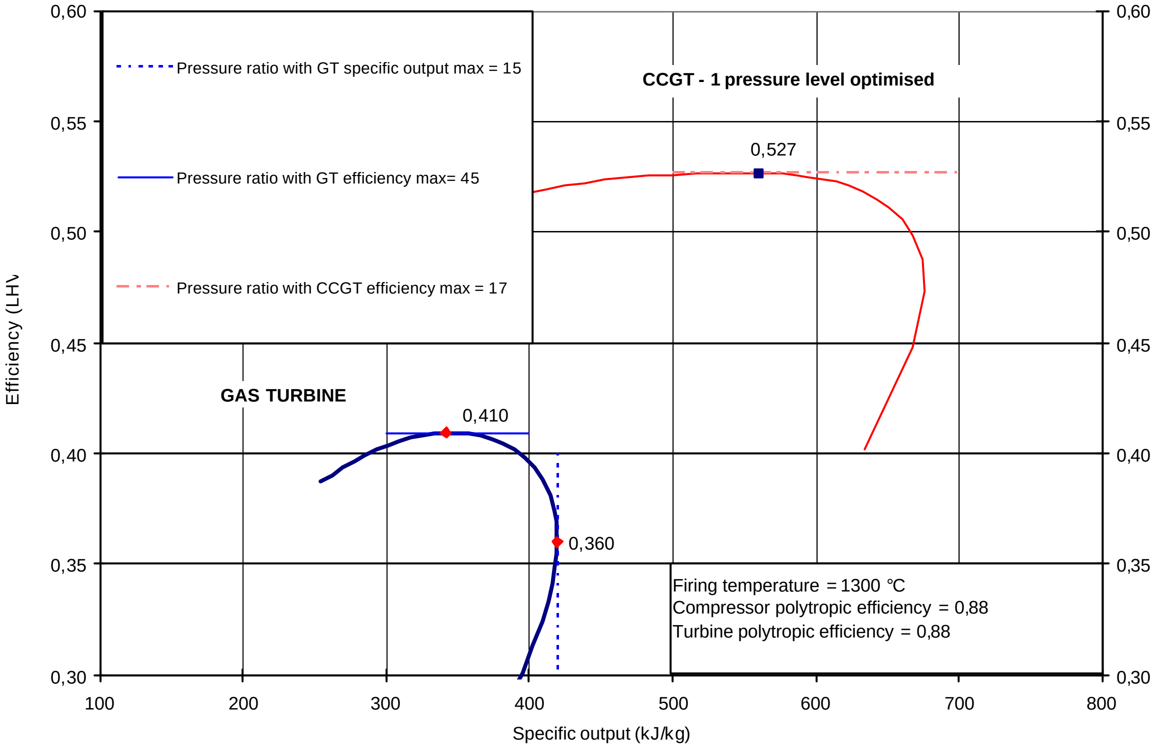

Figure 3-2 : thermodynamics of GT and CCGT cycles

For a comparison with large-scale coal power plants such as IGCC and PC-USC, we have then focused on <u>heavy frame gas turbines</u> for combined cycle configuration.

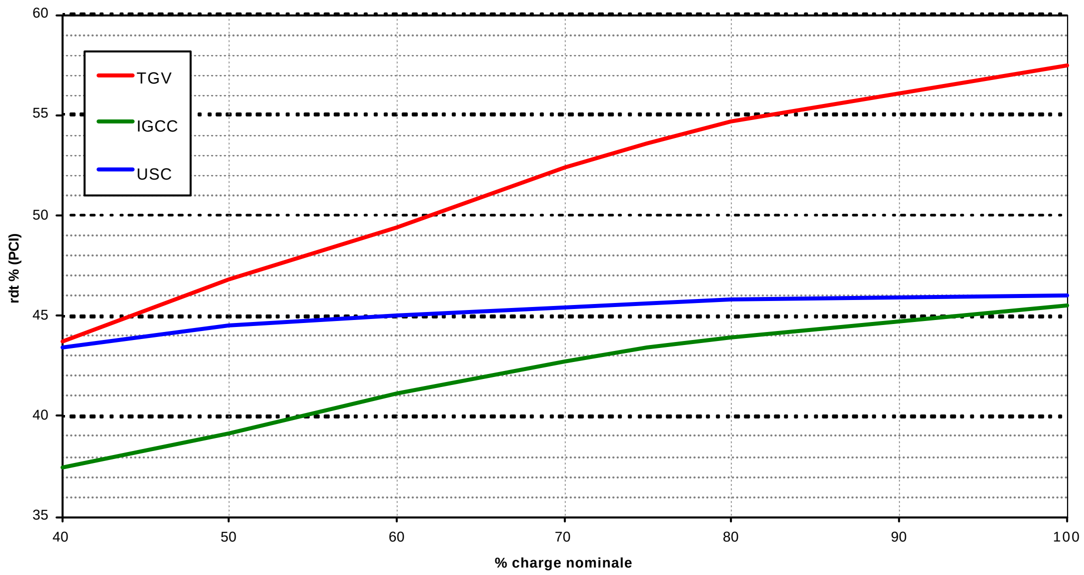

Figure 3-3 : Part load efficiency of STAG, IGCC and USC

3.1.1 Gas Turbine

Efficiency

Figure 3-4 shows that for heavy frame gas turbines (P>50 MW), there is no significant scale-effect. The range of efficiency is 33%…39%.

Investment cost

Figure 3-5 shows the effect of size on gas turbine equipment cost (in 2000 U.S. dollars). The observed scaling exponent is 0,77 which is lower than the value indicated in *(Bejan, 1996).* For turnkey gas turbine power plant, the investment cost are 1,5…2 times higher than equipment cost indicated in Figure 3-5.

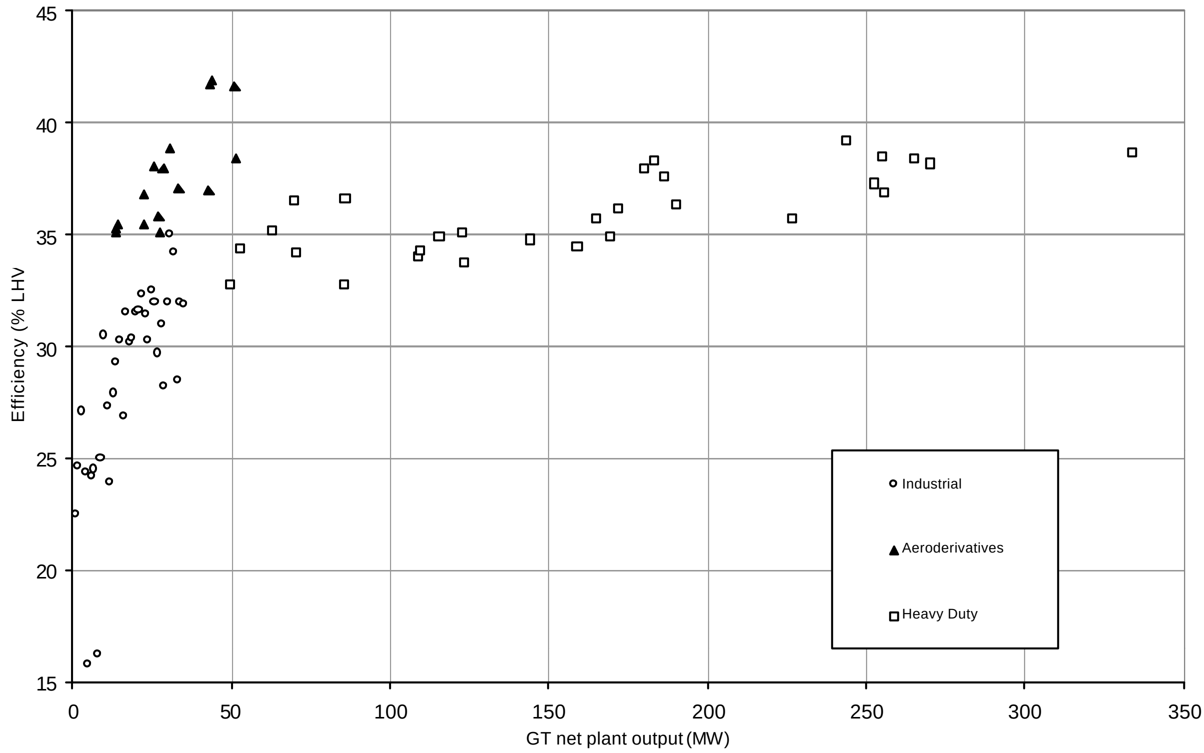

Figure 3-4 : current efficiency of gas turbines (*GTW, 1996-2001*)

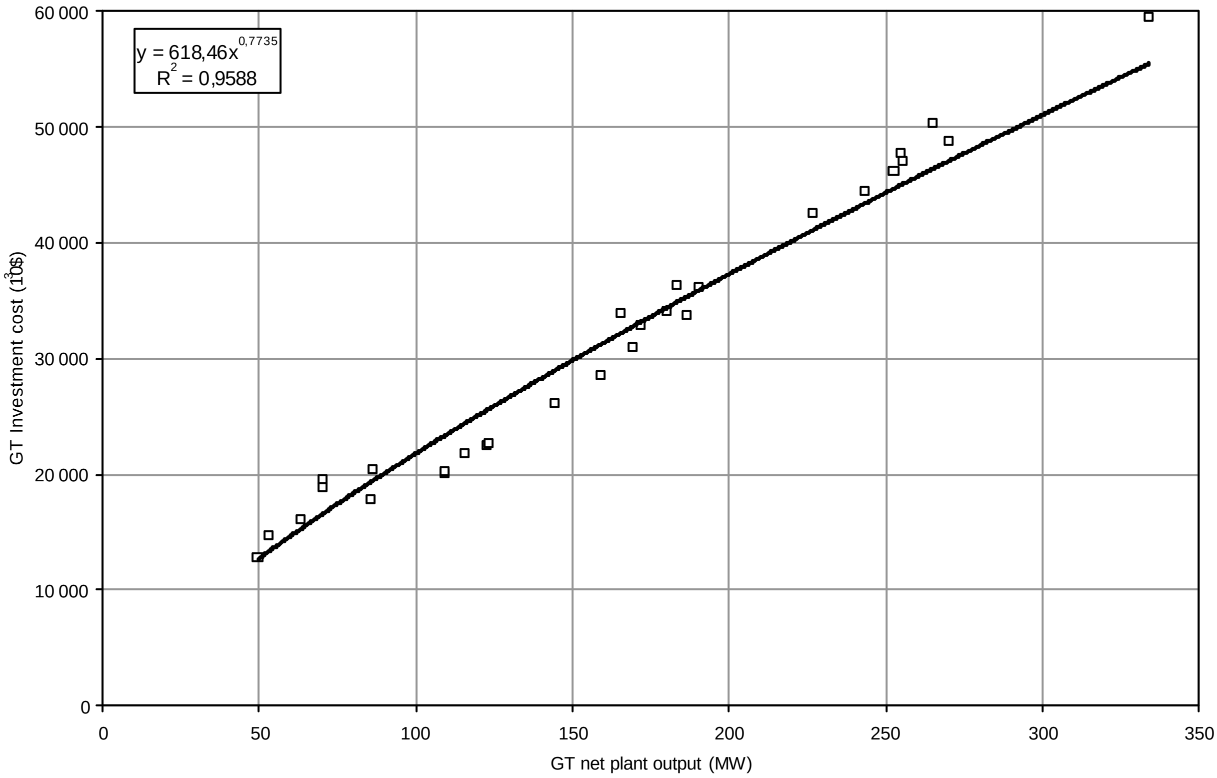

Figure 3-5 : effect of size on GT equipment cost (*GTW, 1996-2001*).

3.1.2 Gas and Steam Combined Cycle

Efficiency

Figure 3-6 illustrates the major influence of the steam cycle configuration (1-pressure level, 2-pressure levels, 3-pressure levels and 3 pressure levels with reheat) on the net efficiency of current commercial CCGT packages (GTW, 1996-2001). Figure 3-6 shows that for units larger than 100 MWe, there is no significant relationship between the efficiency and the power plant capacity.

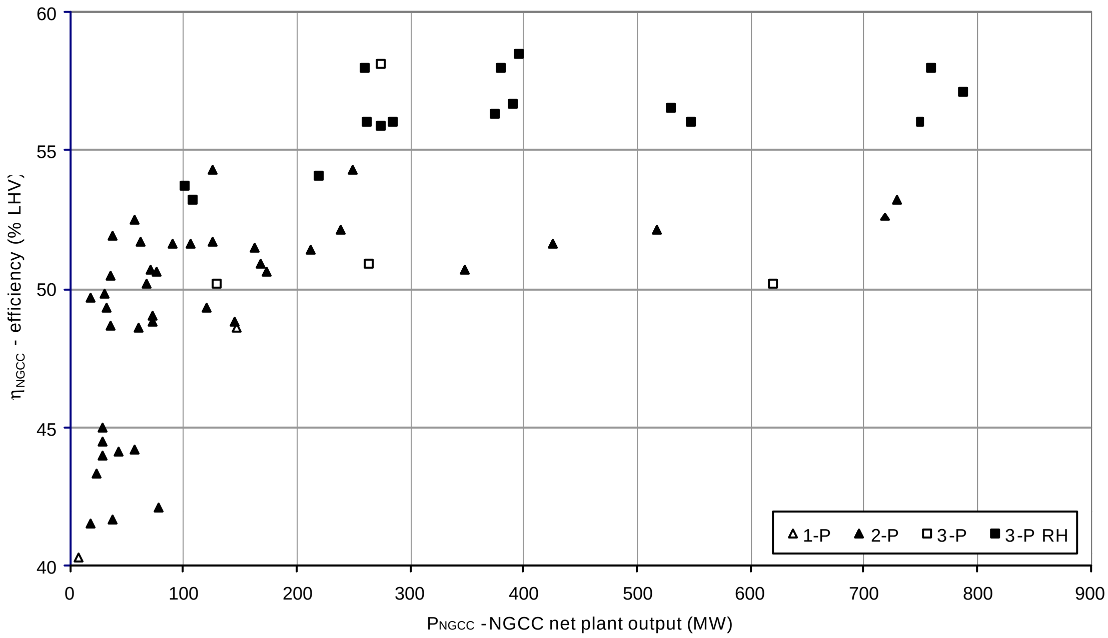

Figure 3-6 : NGCC efficiency, LHV basis (*GTW, 1996-2001*)

Figure 3-7 illustrates the major influence of the power plant capacity on the investment cost (in 2000 U.S. dollars). The scale factor obtained is close to 0,7.

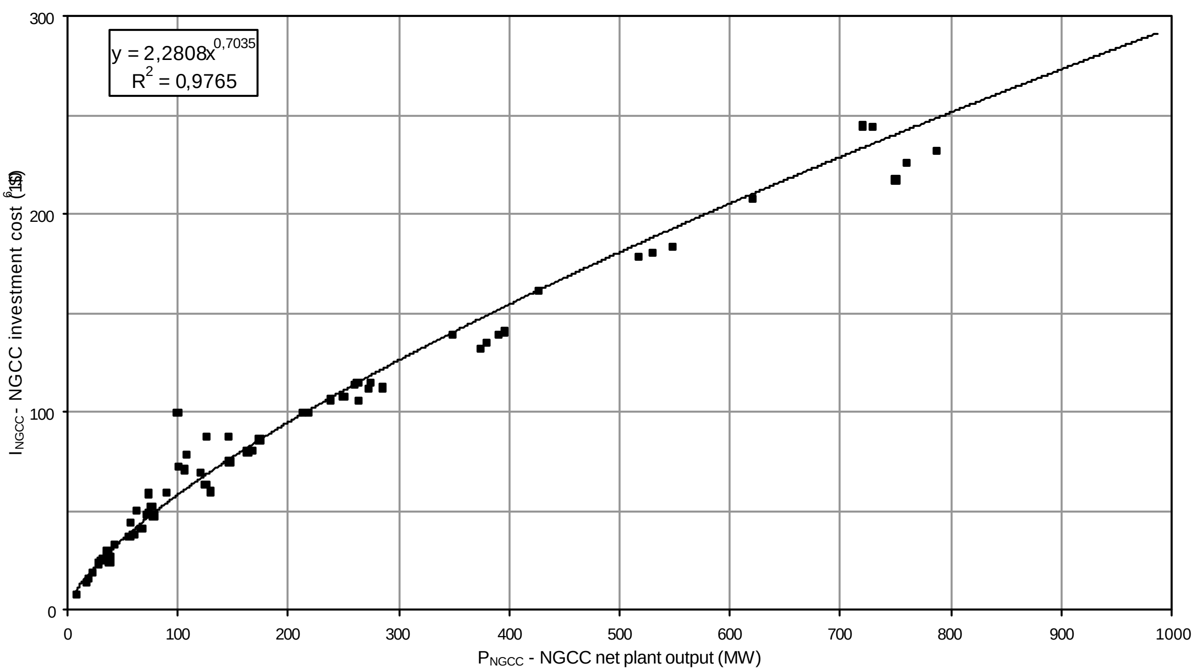

Figure 3-7 : NGCC investment cost : effect of size (*GTW, 1996-2001*)

Figure 3-8 shows the corresponding evolution on the specific investment cost and Table 3-1summarises the value finally considered for the economic analysis.

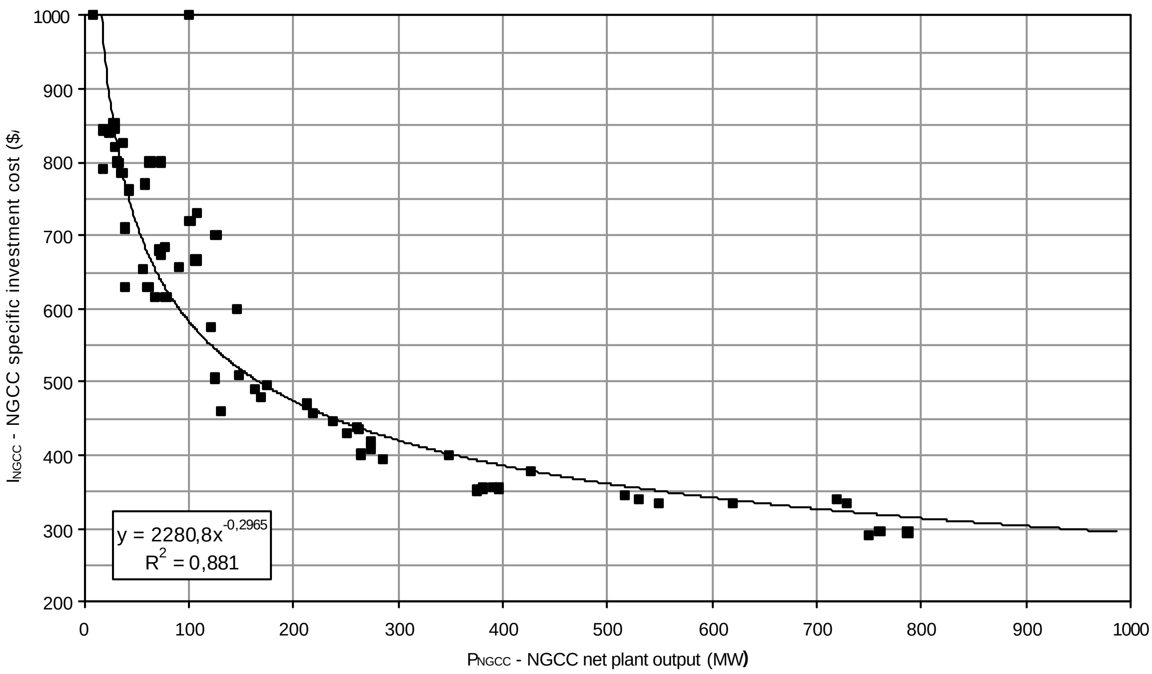

Figure 3-8 : NGCC specific investment cost : effect of size (*GTW, 1996-2001*)

NGCC	min	mean	max	
Investment cost	300	400	500	EUR/kW
Efficiency	52	55	58	% LHV

Table 3-1: NGCC current performances

3.2 Evolution of CCGT performances

NGCC improvements are mainly driven by gas turbine developments related to firing temperature (material, cooling techniques) and by advanced thermodynamic cycle (intercooling, reheat, hybrid cycle,…). Projections from gas turbine manufacturers and R&D programmes such as the ATS programme in USA are described in (*Maude, 1995, Cohn, 1997 and Flin 2000*).

The study has been limited to the analysis of the evolution of specific investment cost and efficiency. Two approaches have been selected in order to describe the evolution of these CCGT performances.

3.2.1 System engineering approach

In a system engineering approach, technological development is considered as an exogenous process, independent of market conditions. Technological improvements and cost reductions are modeled as a function of time according to manufacturer's forecast.

Efficiency

For CCGT efficiency, the main parameter is the firing temperature of the gas turbine. Whatever the complexity of the combined cycle (number of steam pressure levels, sequential combustion, intercooling,…) the efficiency is still limited by the Carnot efficiency :

$$\eta_{carnot} = 1 - T_{min} / T_{max}$$

where Tmax corresponds to the firing temperature of the gas turbine and Tmin to the cold-end temperature (air ambiant or cooling water).

Evolution of this firing temperature is driven by material and cooling system developments (Maude, A995, Lakshminarayana, 1996). Figure 3-9 shows the predicted firing temperature evolution of heavy frame gas turbine and corresponding efficiency enhancement between 1950-2010.

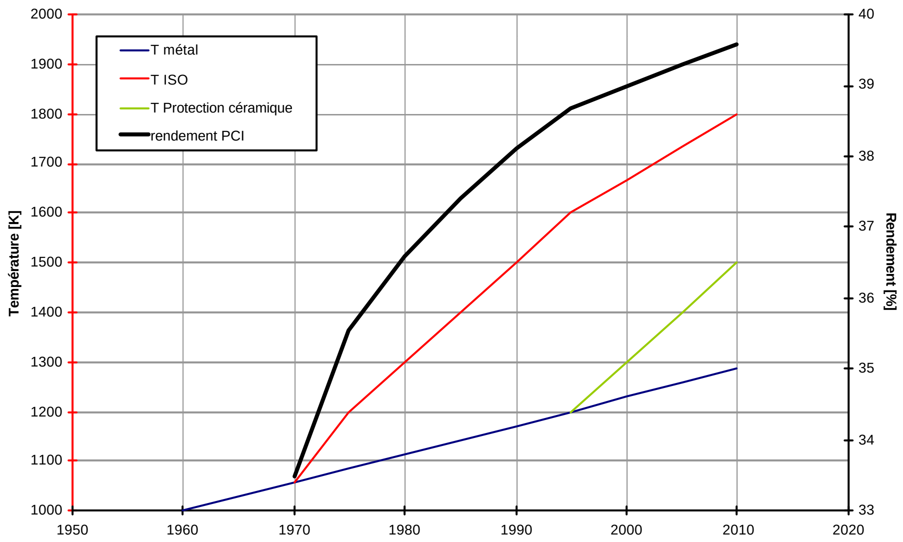

Figure 3-9 : Heavy Duty gas turbine efficiency evolution (VGB, 1999)

Specific investment cost

For CCGT specific investment cost, correlations from cost engineering databases and thermoeconomics analysis have been considered (*Bejan, 1996, Massardo, 2000, Agazzani 1997, Consonni, 1992*). These correlations give the cost of each component (compressor, combustor, expander, steam turbine,…) in function of thermodynamic parameters (firing temperature, pressure ratio, mass flow rate, ….). These correlations must be calibrated and indexed. If they are usefull when comparing various gas turbine based cycles at a given time period, it doesn't help us to provide the evolution in time of these calibration parameters.

3.2.2 Experience curves approach

Efficiency

Figure 3-10 shows the experience curve observed for Belgian STAG power plants from 1969-2001 (Table 3-2). The progress ratio observed (93%) is very similar to those observed for the whole CCGT technology (*Claeson, 2000*).

POWER PLANT	Power Output (MW)	Gas turbine	Recovery steam boiler	Steam turbine	cooling circuit	%LHV	Start-up
ANGLEUR 1	50	Cockerill-Sulzer Multi-shaft (1x23 MW)	1 x CMI Post-combustion 31 bar - 450 °C	La Meuse-Rateau 1x 28 MW	N.A. Wet cooling tower	32%	1969
ANGLEUR 3	117	Westinghouse / ACEC W251-B7 Multi-shaft (2x40 MW)	2 x CMI Post-combustion 30 bar - 460 °C	La Meuse-SOGET 1x 37 MW	N.A. Wet cooling tower	42%	1978
DROGENBOS	460	Siemens V94.2 Multi-shaft (2x150 MW)	2 x CMI 80 bar - 525 °C 7 bar - 216 °C	GEC-Alsthom 1x175 MW	60 mbar Wet cooling tower	52%	1994
SERAING	460	Siemens V94.2 Multi-shaft (2x150 MW)	2 x CMI 80 bar - 525 °C 7 bar - 216 °C	GEC-Alsthom 1x175 MW	60 mbar Wet cooling tower	52%	1994
HERDERSBRUG	470	Siemens V94.2 Multi-shaft (2x160 MW)	2 x CMI 84 bar - N.A. °C 7 bar - N.A. °C	GEC-Alsthom 1x175 MW	56 mbar Air-cooled condensor Hamon-Lummus 6x6 fans	52%	1997
GENT-RINGVAART	350	GEC-Alsthom 9001 FA Single shaft (1x 225 MW)	1 x CMI 112 bar - N.A. °C 32 bar - N.A. °C (Reheat) 5 bar - ? °C	GEC-Alsthom 1x 125 MW	Hamon-Lummus 56 mbar Air-cooled condensor 5x5 fans	55%	1997
SAINT-GHISLAIN	350	GEC-Alstho 9001 FA Single shaft (1x 225 MW)	1 x CMI 110 bar - 565 °C 28 bar - 565 °C (Reheat) 4 bar - 265°C	GEC-Alsthom 1x 130 MW	Hamon-Lummus 63 mbar Air-cooled condensor 4x6 fans	56%	1999
ESCH-SUR-ALZETTE (TWINerg)	380	GEC-Alsthom 9 FA+ Single shaft (1x 250 MW)	1 x CMI 110 bar - 565 °C 28 bar - 565 °C (Reheat) 4 bar - 265°C	GEC-Alsthom 1x 130 MW	Hamon-Lummus 63 mbar Air-cooled condensor 4x6 fans	57%	2001
VILVOORDE 1	380	Siemens V94.3 Single shaft (1x255 MW)	1 x CMI 125 bar - 560 °C 34 bar - N.A. °C (Reheat) 5,6 bar – 167 °C	ABB 1 x 125 MW	Wet cooling tower	57 %	2001

*** STAG back-pressure cogeneration plants not included**

Table 3-2 : STAG in Belgium (2001), source Electrabel and SPE

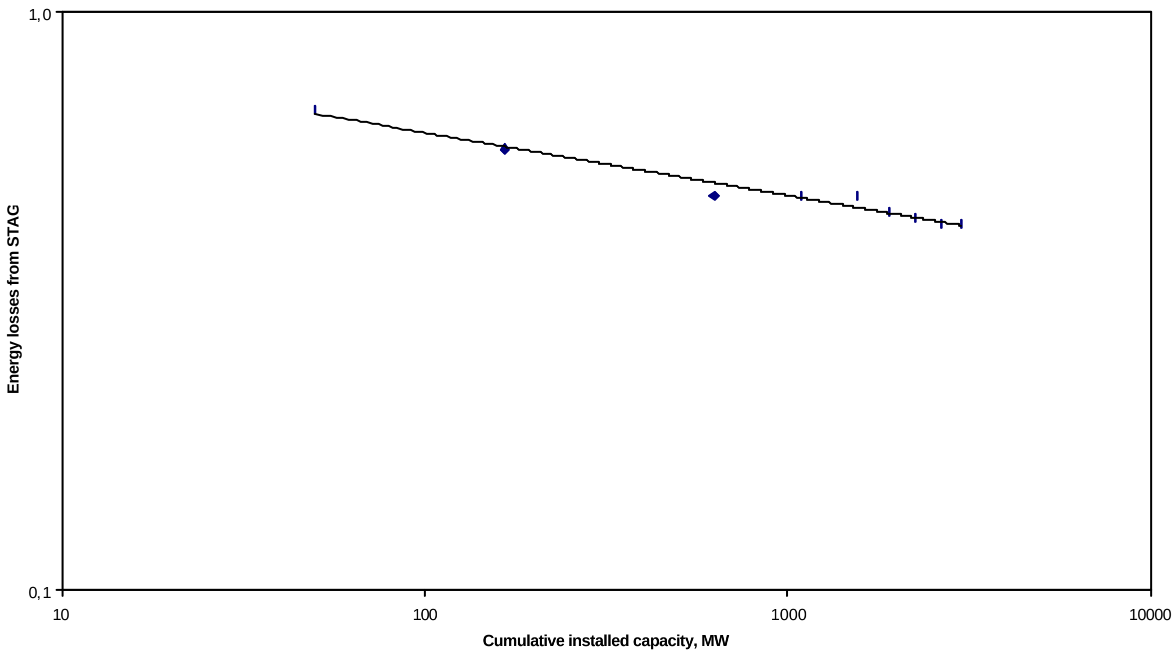

Figure 3-10 : Experience curve for energy losses (1-η) from STAG power plants in Belgium for period 1969 –2001 (progress ratio observed is 93%).

Specific cost investment

Specific investment prices evolution is available for the period 1991-2001 (*GTW 1998-2001, Claesen, 2000*). Progress ratio calculated is 75%.

Evolution in time

Progress ratio gives the relationship between the performance and the cumulative installed capacity. In order to provide the evolution in time of the performance, a scenario for market penetration of CCGT power plants must be selected. Figure 3-11 shows scenario based on experience curves analysis for NGCC and IGCC *(Charpin, 2000)*.

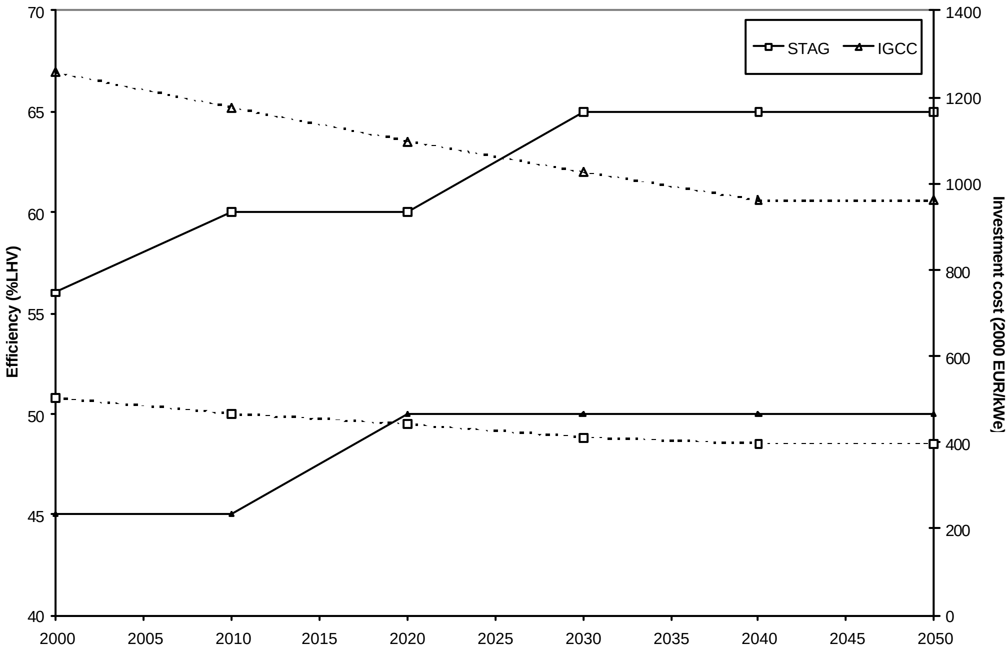

Figure 3-11 : scenario for NGCC and IGCC performances

4 SUPERCRITICAL PULVERISED-COAL POWER PLANT (PC-USC)

4.1 Conventional pulverised coal technology

In Europe, centralised coal-based power generation is mainly achieved by pulverised-coal technology with subcritical and supercritical (SC) steam cycle.[2] Subcritical units represent the major part of coal-based units and correspond to relatively old units with main steam pressure about 170 bars for natural circulation with steam separation drum boiler and 190 bars for once-through (forced) circulation boiler, both with main steam and reheat temperatures about 540°C. Efficiencies attainable by existing subcritical units equipped with low-NOx burners and wet limestone FGD range between 36 to 38%. Increase in generation efficiency can be achieved by increasing the steam conditions through developments in material technology. Evolution of pulverised fuel technology steam parameters and corresponding materials during last decades is reported in Table 4-1 and Figure 4-1.
Since early '80, particularly in Japan and in Europe (Denmark and Germany), the trends has been towards high supercritical units which achieve efficiencies over 40%. Currently more than 170 supercritical boilers are in operation world-wide. Some recent European supercritical power plants are presented in Table 4-2.
Typical features of supercritical power plants are once-through circulation boiler, due to the lack of any density difference between steam and water for supercritical steam pressure, with main steam pressure about 250 bars and temperatures limited to 540°C and 560°C for reheat.

Period	Drum boilers Pres. (bars)	Once-through boilers Pres. (bars)	Temp. (°C)	High temp. Steel
50s	80-100	-	520-530	13CrMo44/T11
60s	120-160	170-180	530-540 560-565	10CrMo910/T22 14MoV63
70s	-	180-190	id.	X20CrMoV121 T22
80s	-	180-190 250	id.	id.
Early 90s	-	250	560	id.

Table 4-1 : Evolution of Pulverised Fuel Technology Steam Conditions

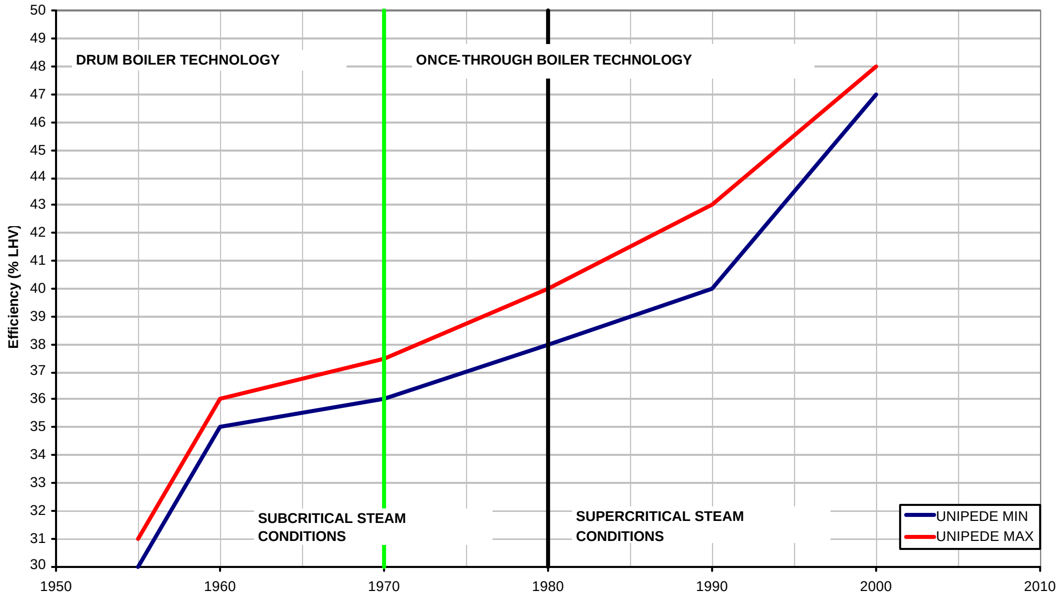

Figure 4-1 : Evolution of Pulverised Fuel Technology Steam Conditions

Power plant		Fyns 7	Esbjerg 3	Staudinger 5 Rostok 1	Hemweg 8
Country		DK	DK	D	NL
Commissioning year		1991	1992	1992	1994
Output	MWe	420	415	509	680
Net efficiency (LHV)	%	43.5	45	43.2	44
Main steam pressure	bars	250	250	262	250
Main steam temperature	°C	540	560	545	535
Reheat temperature	°C	540	560	562	563
Feedwater temperature	°C	280	275	270	N/A
Condenser pressure	mbars	27	23	38/52	31
Ambient temperature	°C	10*	10*	N/A	N/A
Stack temperature	°C	122	105	N/A	N/A

* sea water cooled units

Table 4-2 : Characteristics of Some Recent European Supercritical Power Plants

Limitations on achievable steam parameters are set by the creep properties of construction materials for thick section boiler, steam lines and turbine components, and by the corrosion resistance of superheater and reheater materials. Materials mainly used for thick components are conventional ferritic steels, ranging from plain C-steel up to conventional German martensitic 12% Cr steel (X20CrMoV121) and allow steam parameters up to 250 bars and 560°C. Above these values, material with higher creep strength is needed for the thick section components. Temperature limitation to 540/560°C is a practical limit to minimise the use of high chrome austenitic steels, particularly for thick section components. This limit generally corresponds to transition between current supercritical conditions and advanced conditions. As reported by operators, supercritical units present the same good operational results as with older subcritical power plants with better efficiency ranging between 40 to 46% depending on cooling conditions.[3] These units are generally fitted with air pollution control equipment for particulate, SO_2 and NO_x. Therefore, supercritical pulverised-coal units coupled with modern available air pollution control equipment could be considered as state-of-the-art technology for new coal-based power plants.

4.2 Advanced PF Technology

Material development The progress achieved in material development (EPRI in USA, COST 501 in Europe and EPDC in Japan) enables today to reach supercritical live steam pressure above 250 bars and temperature above 560°C. Table 4-3 summarizes advanced steam conditions and efficiency evolution due to material development.[4]

Steam conditions	Efficiency	Material (pipes, boiler, headers)
250 bars / 540 / 560 °C	43.2 (Staudinger 5)	F12
270 bars / 580 / 600 °C	44.5	P91
300 bars / 600 / 620 °C (USC)	45.2	NF616
315 bars / 620 / 620 °C (USC)	45.6	Austenite
370 bars / 700 / 720 °C (USC)	47.7	Inconel

Table 4-3 : Evolution of Advanced Steam Conditions and Efficiency due to Material Development

Table 4-4 gives the classification proposed by UNIPEDE. Above 300 bars, steam conditions are named ultra-supercritical (USC).[3]

Cycle	SC	ASC	USC	USC
Year	1990	2000	2005	2010
Live steam pressure	250 bar	275 – 300 bar	320 – 330 bar	
Live steam temperature	540 – 560 °C	580 – 600 °C	610 – 620 °C	
Reheat steam temperature	560 °C	580 – 600 °C	620 – 630 °C	
Reheat				
Final feedwater temperature				

Table 4-4 : UNIPEDE classification

The new ferritic and martensitic steels (P91, HCM12 and NF616) which can be used for high temperature components such as reheaters, collectors, live steam pipes and high-pressure turbine casing, are more expensive than the conventional high-temperature ferritic steels which have been used up to now but these additional cost are compensated by efficiency improvement and thus fuel saving.
At present, the ultimate stage of development is fixed to live steam conditions up to 375 bars/700°C including double reheat up to 720°c (e.g. JOULE/THERMIE programme). Depending on the respective steam cooling conditions, efficiencies in the range from 50.5 to 52.5% are expected.[4] These conditions require use of Ni-based alloys like Inconel 617. At present, additional costs can not be compensated by fuel saving.[5] Table 4-5 shows advanced PF coal, lignite or gas-fired power plants in construction or projected in Europe and Japan.[3][4][6]

Project / Plant	Output MW	Steam conditions	Efficiency	Comm.
Denmark				
CONVOY (ELSAM) Skaerbek 3/Nordjylland 1	400	290 bars / 582 / 580 / 580°C	47% - 49%	1997/1998
Avedore 2 (ELKRAFT)	400	300 bars / 580 / 600°C	48%	2000
USC 2005 (ELSAM)	N/A	330 bars / 610 / 630 / 630°C	51%	2005
Germany				
Bexbach II	750	250 bars / 575 / 595 °C	46%	planned
Schwarze Pumpe A/B	800-900	250 bars / 580 / 600 °C	N/A	planned
Frimmesdorf	950	250 bars / 580 / 600 °C	45%	planned
Lübeck	400	275 bars / 580 / 600 °C	46%	planned
Hässler	700	275 bars / 580 / 600 °C	45%	planned
Franken II	600	270 bars / 570 / 590 °C	46%	planned
Schkopau A/B	450	285 bars / 545 / 560°C	40%	1995-96
Boxberg Q/R	818	268 bars / 545 / 583 °C	41.7%	1999-00
Lippendorf R/S	900	268 bars / 554 / 583 °C	42.3%	1999-00
USC - EU project	-	375 bars / 700 / 720 °C	55%	2010
Japan				
Kawagoe 1&2	700	319 bars / 571 / 569 / 569	N/A	1989-90
Hekinan 3	700	255 bars / 543 / 593 °C	N/A	1993
Nanao-ohta	500	246 bars / 566 / 593 °C	N/A	1994
Noshiro 3	600	246 bars / 566 / 593 °C	N/A	1994
Haranomachi	1000	246 bars / 566 / 593 °C	N/A	1997
Matsuura 2	1000	255 bars / 598 / 593 °C	N/A	1997
-	-	246 bars / 593 / 593 °C	N/A	planned

Table 4-5 : Advanced PF Power Plants in Construction or Projects in Europe and Japan

Process and component development In addition of steam conditions enhancement, Rankine steam cycle efficiency can be improved by design modifications such as double reheat, level of regenerative feed water preheating optimisation, lower off-gas temperature and sea water cooling.
For the double reheat, the gain in net efficiency, as compared to single reheat cycle, increases with steam conditions as shown in Table 4-6.[6] Another advantage of the introduction of double reheat, is the reduced wetness of the exhaust steam allowing lower condenser pressure without turbine damage.
Nevertheless, efficiency enhancement due to double reheat is moderated by additional pressure losses, additional capital cost and increased complexity of the plant with more difficult control of reheat steam temperatures especially at part load operation. In the current context of low steam coal prices, cost-effective advantage of double reheat for advanced PF power plants is still not demonstrated. Results from the CONVOY projects in Denmark will reduce this uncertainty.
Improvements of main components efficiency such as boilers (once-through,...), turbine blading, pressure drop, reduced auxiliary power (pumps, fan,...) have also contributed significantly to enhance thermal efficiency of PF technology.
Development in air control equipment aiming at lower efficiency and cost penalties will also contribute substantially to enhance PF technology cost-effectiveness.

Steam conditions	Absolute gain in net efficiency
300 bars / 600 / 600 °C	+ 2.5 %
325 bars / 620 / 620 °C	+ 3 %

Table 4-6 : Gain in Net Efficiency with Double Reheat Cycle compared to Single Reheat Cycle

4.3 Combined Cycle Gas Turbine Configuration

At present, particular attention is given to opportunities for combined cycle gas turbine configuration, either existing conventional PF power plants (repowering) or for new advanced PF power plants. These options allow increased output, thermal efficiency and environmental performances.

For repowering, three options are generally considered:
1. Fully-fired combined cycle where exhaust gases from a gas turbine are used, instead of an air preheater, into the boiler windbox to combust the fuel due to the residual oxygen content,
2. Parallel-powered combined cycle, where exhaust gases are used in a separated heat recovery boiler supplying steam to the main plant (IP turbine inlet).
3. Feedwater heating arrangement, where exhaust gases are directly used for heating the condensate and feed water such a regenerative feed water preheater. This option is the most simplest way.

An example of new capacity is given by the multi-fuel high efficiency power plant concept of Elkraft (Denmark) planned for commercial operation in late 1999.[7] In this concept, feedwater heating of a supercritical pulverised coal power plant with 48% efficiency is achieved by means of exhaust gases of a high efficient aeroderivative gas turbine. With this configuration, natural gas efficiency will reach 60%.[7]

4.4 Current Pulverised Coal Technology Performances

Table 4-7 summarizes current PF performances.[8] Both subcritical and supercritical units are commercially available in a wide range of size. Compared with subcritical PF plant, supercritical PF plant, with its inherent improvement in cycle efficiency and consequently lower specific flue gas throughput, is a cleaner method of electricity generation.

PF technology provides a great fuel flexibility but for a particular plant, the design of boiler and auxiliary equipment must be optimized for a specific coal. Higher temperatures encountered in supercritical units make corrosion more critical. Coals with high slagging or corrosion potential are consequently less suited to supercritical units.

PF technology provides good operational flexibility with stable operation within the range of 25-100% maximum continuous rating (MCR). The practical limit for commercial part load operation is usually at a load determined by the need to introduce oil or gas firing to maintain PF combustion stability. Part load operation is achieved by use of sliding pressure where main steam pressure will vary proportionally to the load. In such a way, the efficiency does not fall off significantly at part load operation. Changes of load (ramping) can be extremely rapid at up to 8% per minute. Time of start-up depends on the steam system with once-through units requiring least time and natural circulation the most. Cold start-up requires between 4 and 8 hours and hot restart takes 1-1,5 hours.

PF plants can achieve very high availability levels. For supercritical units, equivalent availability (total output of the plant over the year as a percentage of the maximum possible output) reach 88-92%, with the majority of the lost availability being attributable to planned outages, averaging about four weeks a year. These tend to be reduced at four weeks every two years.[3]
Because of the large boiler sizes, most of the plants has to be erected on site and therefore, compared to other more compact technology, there is relatively less scope for modularisation and off-site construction. Developments have still to be done to overcome this drawback.

PF technology with supercritical steam conditions and more than 170 units in operation world-wide is the most mature technology. Commercially available sizes range from 50 MWe to more than 1000 MWe. State-of-the-art supercritical power plants have an efficiency about 46% and satisfy current emission standards. For advanced PF technology, main progress will be achieved in material development allowing higher steam conditions and consequently enhanced efficiency. Efficiency up to 55% is announced for 2010 by adoption of ultra-supercritical conditions about 375 bars and 700/720°C.

Parameter	Subcritical	Supercritical (state of the Art)
Maturity	Fully commercial	Commercial
Unit size	50-1000 MWe	id.
Fuel flexibility	Wide range from anthracite to lignite with ash and moisture content up to 60%.	id.
Net efficiency (LHV) (50 mbars, 120°C stack, 15°C ambient)	36-38%	40-46%
Operation performances Load range Load ramp rate Start up (hot) start up (cold)	25-100% MCR 8%/min 1-1.5 hrs 4-8 hrs	id.
Emissions (6% O_2, dry flue gas) SO_2 (1% sulphur content) SO_2 (3% sulphur content) NOx (Selective Catalytic Reduction) NOx (no SCR) Dust	100 mg/Nm^3 200 mg/Nm^3 200 mg/Nm^3 650 mg/Nm^3 10-25 mg/Nm^3	id.
Solid residues	Ash : disposal or valorization Gypsum : valorization	id.
Equivalent availability	86-92%	id.
Planned Outage factor	8%	id.
Build time	38-58 months	id.
Specific capital cost (1$ = 1,23 euro)	950-1300 $/kW	950-1600 $/kW

Table 4-7: Current Subcritical and Supercritical PF-Fired Power Plants Characteristics

5 INTEGRATED COAL GASIFICATION COMBINED CYCLE TECHNOLOGY (IGCC)

An IGCC plant consists of a combined cycle gas turbine fuelled by a synthetic fuel gas produced by a gasifier, where oxidant supply is completely or partially integrated with the gas turbine and the various heat exchangers from the gasifier and syngas cooler contribute to the steam cycle. The IGCC process is composed of three main units (gasification system, clean-up system and combined cycle gas turbine) and auxiliary units (cryogenic air separation unit, Claus unit, waste water treatment unit,...). The degree of integration of these units leads to various configuration options.

5.1 Gasification Systems

Coal gasification processes can be classified according to several major criteria:

- flow regime: fixed or moving bed, fluidised bed and entrained bed,
- autothermal (adiabatic) or allothermal gasification,
- operating temperature*,
- operating pressure,
- type of fuel feed: water slurry (wet) feed, nitrogen carrier feed, paste feed, lockhopper solids,
- reactant gases: steam/oxygen or steam/air ratio,
- product gases temperature and composition,
- nature of solid waste discharge : dry solid, softened agglomerated solid or molten slag*.

*Operating temperature and nature of solid waste discharge are mainly fixed by steam/oxidant ratio and gasifier heat exchange conditions.
Table 5-1 summarizes basic types of some coal gasification reactors available to be integrated into a combined cycle power plant.[10][11]

Flow regime		Moving or fixed bed	Fluidised bed	Entrained flow
Temperature	°C	800-1000°C	800-1000°C	1500-1900 °C
Pressure	bars	10-100	10-25	25-50
Outlet gas temp.	°C	400-800°C	800-1000°C	1300-1600 °C
Coal size	mm	3-30	1-5	0.1
Solid waste		see below	agglomerated solid	molten slag
Processes		*Oxygen/air - dry feed* Lurgi dry ash *Oxygen - dry feed* British Gas/Lurgi slagging	*(Oxygen)/air-dry feed* HTW KRW Tampella (U-Gas) Lurgi Ahlström British Coal	*Oxygen/dry feed* Shell, Prenflo, Deut. Babcock *Oxygen/ wet feed* Texaco, Dow (Destec) *Air/ dry feed* MHI, ABB Combustion-Engineering

Table 5-1 : Gasification Systems

For moving bed, steam and oxidant feed countercurrent to coal as for result a high ash content in the fuel gas. These tars are removed by water scrubbing and recycled.
For fluidised bed, sorbent (limestone) is injected for in-situ desulphurisation. Air is used rather than oxygen to keep temperature below ash fusion point.
For entrained flow, the gasification is carried out above the ash fusion temperature in order to vitrify the ash in an inert, crystalline non-leachable form. Then, the fuel gas must be cooled by heat exchangers raising steam or quench (syngas cooler) to match conventional gas cleaning system.

Oxidant type The objective of most commercial coal gasification applications is the production of synthesis gas (CO and H_2). In this case, the presence of diluent nitrogen is undesirable while for power generation, where product gas is used directly, this presence may be acceptable.

Nevertheless, air blown gasifier produces a lower LHV fuel gas, needs greater equipment due to higher gas flow and achieves lower carbon conversion.
Among gasifier types, entrained flow gasification systems attract the widest interest for IGCC power generation. Most of them operate at high temperature in the slagging mode. Slagging conditions are difficult to achieve in air blown gasifier so that attention has been directed toward the use of oxygen blown systems which require an integrated cryogenic air separation unit (ASU).

Fuel feed Coal may be fed into the gasifier in a number of different ways, which include:
- water slurry feed,
- dry pulverised coal, with nitrogen carrier gas,
- paste feed,
- lockhopper solids.

Wet feed is achieved by preparing the fuel in the form of a coal-liquid mixture, usually coal/water slurry (50% to 70% solids concentration). Although the slurry system has advantages in terms of safety, control and ease of operation across a pressure boundary, the total quantity of water fed into the reaction zone is determined more by the required flow properties of the slurry than the gasification process itself. For this reason, high moisture content coals are not suitable. To overcome this problem, other developers favour dry feed systems (e.g. nitrogen carrier) where the total water supplied to the reaction zone can be maintained under independent control and optimized for the gasification process over a range of operating conditions.

5.2 Raw Gas Pollutants and Cleaning Goals

Pollutants contained in the fuel gas leaving the gasifier could be classified in two categories according to cleaning processes required for their removal:
- particulate (fly-ash), tars, condensed organics, trace elements, aqueous soluble components of NH3, HCN, the free and reduced halogen gases (HF, HCl). These are removed by cyclones, filtration and wet scrubbing. Fly-ash are recycled to the gasifier.
- sulphurous acid gases and CO_2 which can't be removed by wet scrubbing systems due to their poor aqueous solubility. Under the reducing conditions found in any gasifier, the sulphur in the coal is mostly converted into hydrogen sulphide (H_2S) rather than sulphur dioxide (SO_2). Sulphurous acid gases contained in the raw gas are in the form of H_2S (>90%), COS and trace quantities of CS_2.

Retention of CO_2 is technically feasible. Studies have shown that the gasification cycle results in the lowest energy use penalties for CO_2 removal from a coal-fired power plant.[12] But ultimate disposal of carbon dioxide constitutes a problem which has not been definitely solved.
Besides emission limitation for particulate, SO_2 and NOx, organic compounds and trace elements, gas cleaning in IGCC are mainly required to avoid gas turbine damage. Gas turbines must be protected from ash constituents which might give rise to deposition, erosion or corrosion of the blades. Higher combustion and gas turbine inlet temperatures (>1000°C) impose more stringent contaminant control goals. These requirements become more critical with higher inlet temperature (~13OO-1400°C) gas turbines which incorporate blade cooling.

5.3 Raw Gas Cleaning

In the pressurised gasification cycles, the lower gas volumes and higher partial pressures of the gaseous and particulate contaminants permit their improved separation during gas treatment.
Conventional commercial processes available for fuel gas purification and suitable for IGCC operate at relatively low temperature, below about 150°C. Use of such systems means that the raw gas leaving the gasifier must be cooled prior to the purification step. Cooling is achieved by heat exchangers integrated to the steam cycle or by quenching. Part of the heat generated by the fuel by-pass in this way the gas turbine which affects overall cycle efficiency.
Downstream syngas cooling, filtration and wet scrubbing steps, various processes are available for removal of H_2S.[13] Generally, H_2S is removed by a liquid sorbent absorption process and is regenerated. H_2S is then converted in a Claus unit to elemental sulphur which can be sold.

To overcome losses in efficiency and eliminate the need for costly heat exchangers, hot gas cleaning systems are developed. In such systems, H_2S is removed at temperatures between 500-700°C. At present, hot gas cleaning is at the stage of demonstration or under development.[13] Waste water produced by the gas cleaning system has to be treated to make it suitable for re-use and disposal of residual sludge.

5.4 IGCC Technology Performances

Current IGCC commercial-scale demonstration projects and status on IGCC performances are respectively given in Table 5-2 and Table 5-3

Plant size The gas turbine dictates the primary efficiency and size of the IGCC system. The gas turbine firing system has to be adapted to a low BTU gas (± 4 MJ/kg). In order to maintain power output, mass flow through gas turbine must increase which in turn increases stresses in turbine and reduces surge margin for compressor. Currently, commercially available low-BTU gas turbine have specific size ranges from 150 to 200 MWe corresponding to an output of 250-320 MWe for a single IGCC train (one gasifier and one combined cycle gas turbine).

Environmental performances IGCC technology presents the best environmental performances of all coal-based technologies, meeting the more stringent air pollution standards.[8][14] Moreover, amounts of solid by-products, valuable, are lower than for the PF technology.[5] Main environmental advantages of IGGC are summarised hereunder:

- Dust: filtration and wet scrubbing in the fuel gas cleaning unit before gas turbine avoid the need for flue gas cleaning. Dust emission are around 10 mg/Nm^3 (6% O_2).
- SO_2: removal of more than 98% of sulphur content is achievable. This corresponds to a sulphur emission of about 75 mg/Nm^3 at 6% excess oxygen. Moreover, sulphur is recovered under to form of elemental sulphur which is saleable product.
- NOx: nitrogen from ASU and water vapour injection in the gas turbine together with low-NOx burners allow NOx emission less than 150 mg/Nm^3 at 6% oxygen.
- Residues: For entrained gasifier, ash is convert to an inert slag where trace elements are locked. Therefore, this residue can be sold as an aggregate. Sludge produced from waste water treatment has to be land-filled. Trace metals and halogens are recovered in the waste water treatment.

Operational performances At present, only two commercial-scale demonstration (entrained flow) units are operating. Therefore, operational flexibility of IGCC are not well-established. Table 9 summarizes estimated operational performances of such IGCC units.[8]
These IGCC units presents the following drawbacks:
- load range limited between 50% to 100% MCR,
- important decrease in efficiency at part load due to the gas turbine (85% of design efficiency at 50% MCR),
- long hot start-up procedures due to the need for gasifier lines purge with nitrogen before restart,
- long cold start-up due to the long time needed to reach ASU cryogenic temperature,
- low ramp rate limited by the ASU behaviour.

For these reasons, IGCC is only considered for base load operation. Load change as well as start-up flexibility are limited by the complexity of the plant and its level of integration. Buggenum and Puertollano have a full integrated ASU scheme, where compressed air is exclusively supplied by the gas turbine in order to avoid an additional air compressor and optimize plant efficiency. Partial integrated ASU scheme provides better operating flexibility and off-design performances due to its two independent air sources. It will be the preferred concept for future projects.

Project	Owner	Fuel	Size (MW)	eff. (%)	Gas. Type	Start-up date
Plaquemine, USA	Dow Chemical	coal	160	N/A	Destec	1987
Buggenum NL	Demkolec (SEP)	coal	253	43	Shell	1993 (demo.) 1998 (comm.)
Puertollano SP	Elcogas	coal + Pet. Coke	315	45	Prenflo	1997
Wabash River USA	PSI/Destec	coal	265	40	Destec	1996
Polk USA	Tampa Electric	coal	260	N/A	Texaco	1996
PinonPine USA	Sierra Pacific	coal	100	40	KRW	1997

Table 5-2 : Some Commercial-Scale IGCC Projects

Parameter	Value
Maturity	Just commercial
Unit size	100-600 MWe
Fuel flexibility	Wide range of coals but limited to low moisture content for slurry feed gasifier.
Net efficiency (LHV)	43-47%
Operation performances Load range Load ramp rate Start up (hot) start up (cold)	 50-100% 5 From 1-1.5 hrs to 2 days 2-3 days
Emissions (6% O_2, dry flue gas) SO_2 NOx Dust	 30-100 mg/Nm^3 100-150 mg/Nm^3 10 mg/Nm^3
Solid residues	Inert slag, elemental sulphur, both valuable
Equivalent availability	75%
Planned Outage factor	8%
Build time	4 years
Specific capital cost	1500-2000 $/kW

Table 5-3 : Current Performances for IGCC Plant [8]

Availability Low current availability performances are inherent in this period of first stage commercialisation. Critical components are the gasifier and the gas turbine firing system with low BTU gas.

Construction issue Little experience can be derived from only two commercial operating units. Purchase is complicated by the need of numerous licences for components such as gasifier and gas cleaning system.
Most of the major plant components (gasifiers, gas turbine,..) can be shop-fabricated and transported to site unlike PF technology.
Moreover, phased construction where the gas turbine combined cycle is, in a first step, natural-gas fuelled and, in a second step, converted to fuel gas from coal gasification may facilitate introduction of IGCC systems.

5.5 IGCC Development

Effective electricity generating cost, availability and operational performances of IGCC technology are not well established due to the lack of commercial-scale units operation. Results gained from current project (see Table 8) will reduce uncertainty relative to these performances.
Main developments will be focused on

- plant efficiency improvements at design and off-design conditions,
- operational flexibility improvement (partial ASU integration),
- availability improvement,
- size range of suitable gas turbines.

Higher net efficiency could be achieved by improvement of the gas turbine combined cycle efficiency or by improvement of the hot gas cleaning system. The gas turbine combined cycle efficiency can be improved by enhanced gas turbine cycle efficiency (higher turbine inlet temperature, intercooling, reheat gas turbine) and by enhanced exhaust gas heat recovery: three pressure levels steam cycle, lower stack temperature, supercritical conditions or by alternative options such as Humid Air Turbine (HAT), Steam Injected gas turbine (STIG) which achieve better efficiencies at part load. Such developments are mainly pursued by gas turbine manufacturers for more efficient natural gas-fired combined cycle and have always to be considered in combination with NOx limitation purposes. Use of two smaller units for one gasifier may also improve part load. IGCC efficiency will also strong depend on hot gas cleaning improvement aiming at higher allowable temperature, lowering exergy losses associated with heat exchangers, and extended life of the sorbents which must withstand successive operation through repeated sulphation and regeneration cycles.[13] At present, efficiency up to 53% are estimated reachable by use of increased gas turbine firing temperature (from current 1120°c to 1250°C ISO), higher steam conditions and hot gas cleaning system. [5]
At present, better operational flexibility are expected from partial integrated ASU. An example is given by the single train IGCC of 400 MW developed by Shell and General Electric. This project is based on results from the former 253 MW IGCC train at Buggenum and would achieve 46% efficiency. Main features are enlarged single train size by use of more efficient gas turbines (GE 9F) in a two-train configuration allowing shared process units such as coal milling, liquid oxygen/nitrogen, water treating and sulphur recovery systems.
An alternative development to IGCC which is also based on coal gasification is the hybrid cycle utilising partial air-blown gasification, with char burn-out in a separate PFBC or CFBC (e.g. British Coal). Efficiencies up to 50% are possible because an air separation unit is not required and high steam conditions can be employed in the fluidised bed.

5.6 Conclusion

IGCC technology is just in the beginning of its commercialisation stage with only one commercial unit built in Europe (Buggenum, The Netherlands) and size range between 100 to 320 MWe. IGCC is the cleanest of all the coal technologies. Efficiency of Buggenum is about 43%. Potential for efficiency enhancement is based on natural gas-fired combined cycle technology development which is inherently greater than the Rankine steam cycle of PF technology. Nevertheless unavoidable exergy losses during the gasification step will always reduce IGCC efficiency compared with natural gas-fired combined cycle where efficiency up to 60% are announced. At present, IGCC power plants are only considered for base load operation and development of such units is still conditioned by remaining uncertainties on operational and availability performances. Results from commercial-scale units will reduce these uncertainties. This current limitation of IGCC to base load operation is the main reason to prefer supercritical PF power plants where coal-based power plants are destined to cover variations in demand.

6 PERFORMANCES COMPARISON

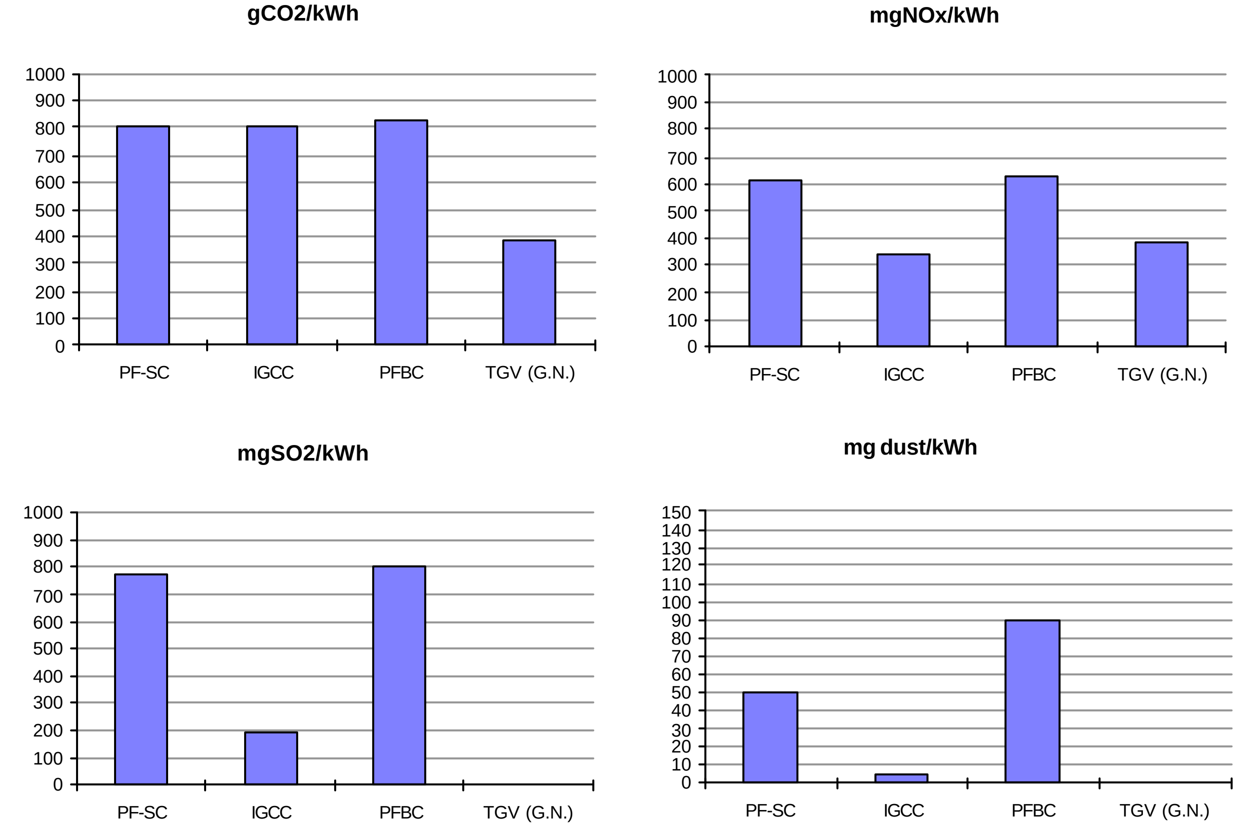

Figure 6-1 : Specific CO2, NOx, SO2 and dust emissions of STAG, IGCC, PFBC and USC

7 CASE STUDIES : NGCC VERSUS IGCC

In this chapter, a simple approach based on the real options theory is proposed to determine the optimal investment decision for a new power plant in an uncertain context. Two projects are considered : a natural gas-fired CCGT power plant (NGCC) and a coal-fired IGCC power plant. In addition, the flexibility value of a phased construction for IGCC power plant is analysed (financial value for the repowering option to convert a NGCC unit into an IGCC unit). The uncertainty considered is the natural gas price evolution. A Geometric Brownian Motion (GBM) stochastic process has been used and calibrated by means of various historical data and scenarios.

7.1 Fuel prices evolution

In most scenarios, due to large reserve of coal and its wide distribution in the world, coal price is supposed to be stable over a long-term period. For that reason and to simplify real options computation, we consider a constant coal price over the entire period. Consequently, only the natural gas price is considered as a stochastic variable.

7.1.1 Stochastic processes

To model the evolution of the natural gas price P(t), a Geometric Brownian Motion (GBM) stochastic process has been used:

$$dP(t) = \mu.P(t).dt + \sigma.P(t).dz \tag{1}$$

$$dz = \varepsilon_t dt^{1/2} \tag{2}$$

where μ is the mean expected growth rate, σ the annual volatility and ε_t is a standard normal distribution. In equation (1), the first term of the right side is the trend (determinist) and the second term is the deviation from the trend (term of uncertainty). The GBM process is easy to implement and has been widely used in financial economics theory [1]. Other stochastic processes are proposed such as mean-reversion models, mean-reversion with jump-diffusion (see [15]) but require more developped computation methods.

From equation (1), given gas price at t_0, gas price distribution can be obtained at any time t according the following equation :

$$D(\ln P(t)) = (\mu - 1/2\ \sigma^2)\ dt + \sigma dz \tag{3}$$

where d(lnP(t)) is a Brownian Motion with Trend with:

$$E[d(\ln P(t))] = (\mu - 1/2\ \sigma^2)dt = \alpha dt \tag{4}$$

and

$$Var[d(\ln P(t))] = \sigma^2 dt \tag{5}$$

The Geometric Brownian Motion is a log-normal diffusion process, with the variance growing proportionally to the time period ($t-t_0$) considered. Figure 7-1 illustrates the possible evolution of the gas price according to this stochastic model.

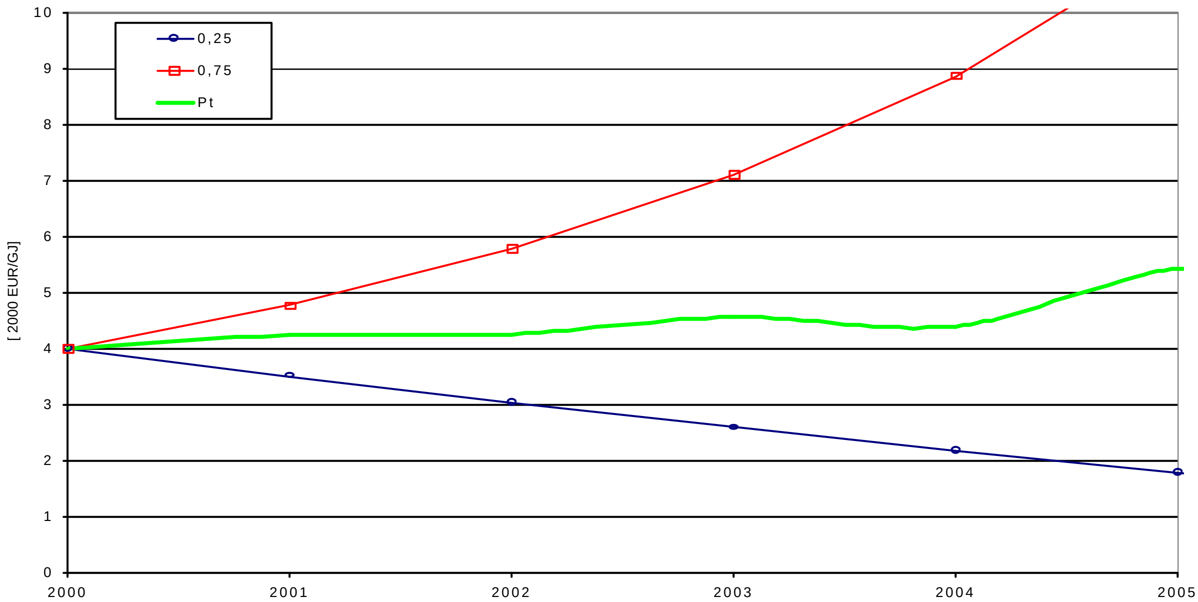

Figure 7-1 : GBM stochastic model (μ = 0,0299 and σ = 0,1165)

Figure 7-2 illustrates the evolution of the probability density function $f_{t0}[P(t)]$ for μ = 0,0299, σ = 0,1165, corresponding to a positive value for the trend α = 0,0231, and $P(t_0)$ = 4 EUR//GJ.

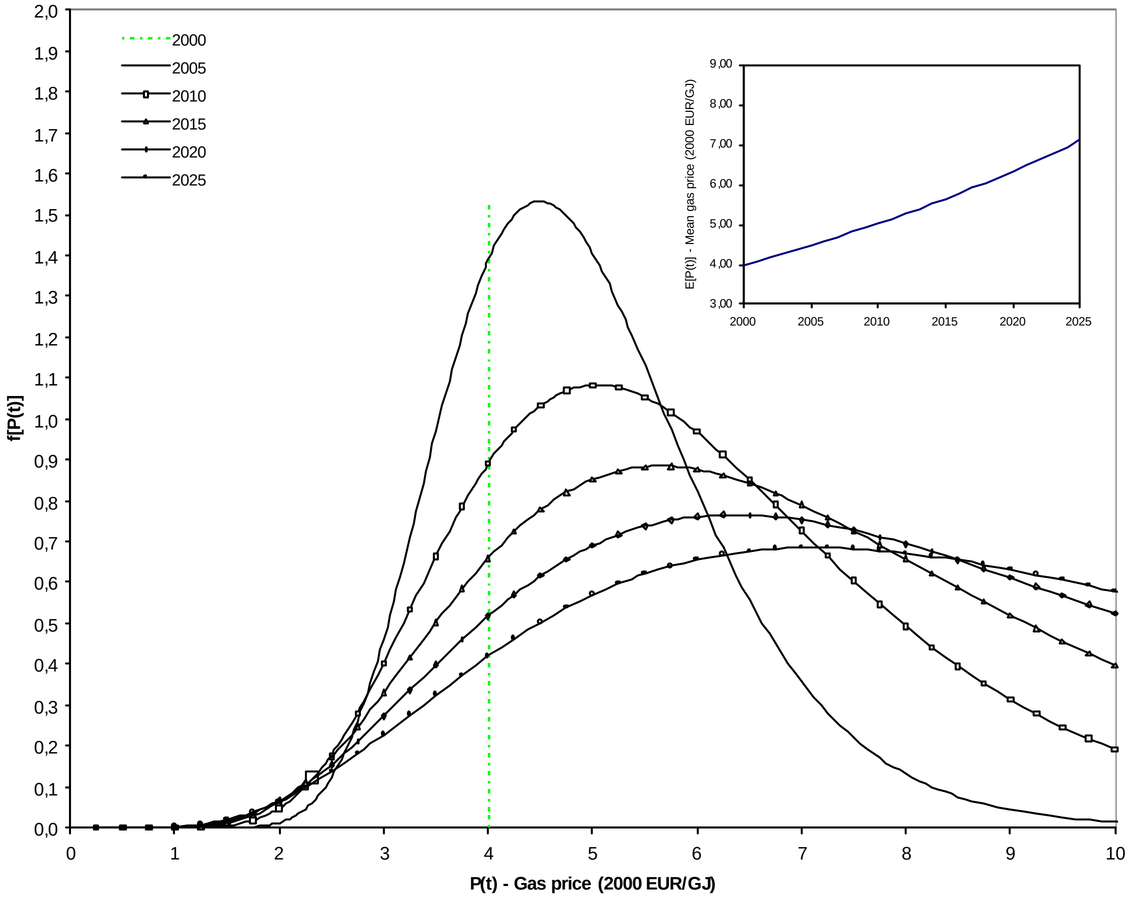

Figure 7-2 : gas prices evolution (μ = 0,0299 and σ = 0,1165)

7.1.2 Calibration

Several calibration of the mean expected growth rate μ and the annual volatility σ have been performed.

A first approach, is based on historical values for the Belgian borderprice "all gases" from 1982 to 2000 [16].

Figure 7-3 : Evolution of Gas Borderprice in Belgium

Several scenarios for Belgium or for Europe have been collected [10-14]. Based on these data, 15 fuel prices scenarios for the period 2000-2010 or 2000-2030 have been considered. Gas prices scenarios considered are illustrated in Figure 7-4.

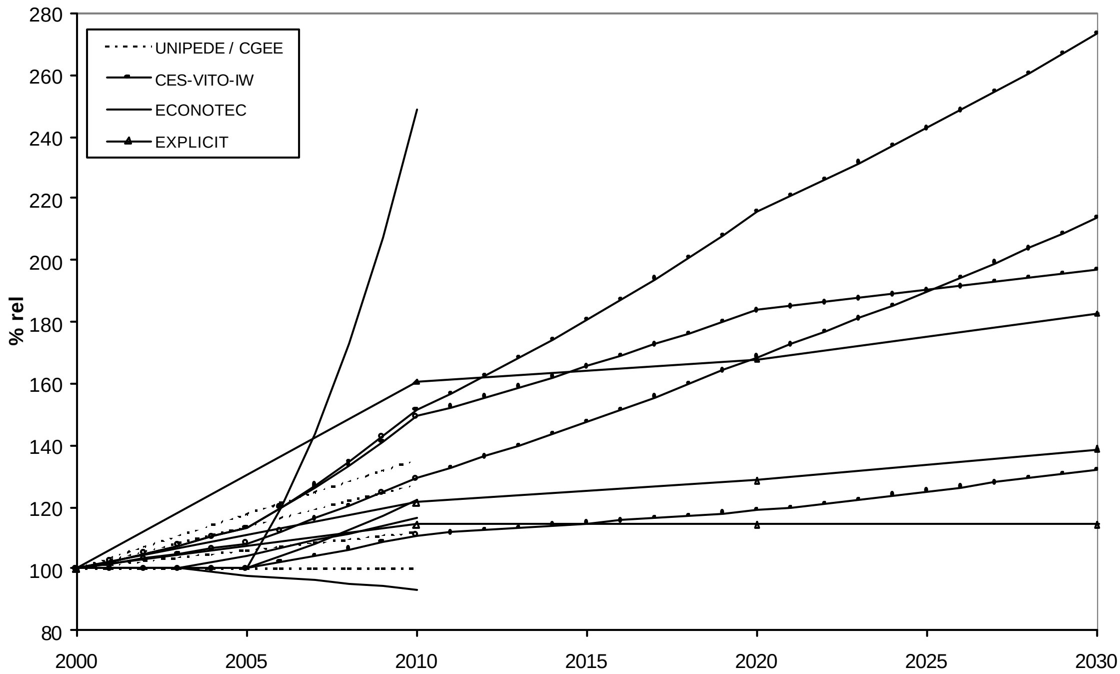

Figure 7-4 : Gas prices scenarios [10-14]

A second calibration has been based on these scenarios [10-14] considering value predicted in 2010 and 2030 and equiprobability of these scenarios. Table 7-1 gives the value obtained for both parameters and compared to other value found in [17-18]. Most of them give a positive value for the trend α of gas prices. It's noteworthy that most of scenarios result generally in lower gas prices volatility than historical value.

Sample period		μ	σ	α	Market	Ref.
1920	1996	0,0210	0,1193	0,0139	USA	[17]
1930	1996	0,0188	0,1079	0,0130	USA	[17]
1940	1996	0,0274	0,1099	0,0214	USA	[17]
1950	1996	0,0424	0,1144	0,0359	USA	[17]
1960	1996	0,0395	0,1259	0,0316	USA	[17]
1970	1996	0,0490	0,1451	0,0385	USA	[17]
1971	1998	0,0000	0,3162	-0,0500	FRANCE	[18]
1982	2000	0,0029	0,2279	-0,0231	BELGIUM	[16]
2000	2010	0,0164	0,0370	0,0157	BE+UE	[10-11]
2000	2010	0,0299	0,1165	0,0216	BE	[12]
2000	2030	0,0227	0,0477	0,0231	BE	[13]
2000	2030	0,0118	0,0351	0,0112	FRANCE	[14]

Table 7-1 : μ and σ GBM parameters

7.2 Economic Analysis

Calculations are based on the discounted cash flow techniques. Discounted electricity generating costs are calculated according to the UNIPEDE method [10].

$$EGC = \frac{I + \sum_{t=1}^{n} \frac{FOM(t)}{(1+i)^t} + \sum_{t=1}^{n} \frac{U(t)\left[VOM(t) + P'(t)\right]}{(1+i)^t}}{\sum_{t=1}^{n} \frac{U(t)}{(1+i)^t}} \tag{6}$$

The reference year is the commissioning year t_0. Interest during construction are included in the investment cost I. All expenditures are exclusive of tax and fiscal charges, and expressed in constant money of the commissioning year t_0 and discounted to this year. Three discount rates of 5%, 10% and 15% are generally considered. For simplification purposes, power plant lifetime n is fixed to 25 years and a constant capacity factor (including availability) of the power plant is considered during all this period. Variable and fixed O&M costs are generally expressed as a percentage of purchased equipment cost but are not considered in this study for simplification.

7.2.1 NPV analysis

A first step in the analysis is the comparaison of the Net Present Value (NPV) of an IGCC project versus a NGCC project where a mean natural gas price evolution is derived from a stochastic process. Table 7-2 summarises inputs used for the reference case calculation.

	NGCC	IGCC	
Investment	400	1200	EUR/kW
Efficiency	55	45	% LHV
Fuel price	4	1,5	EUR/GJ

Table 7-2 : Data for the reference case

Influence of the annual utilisation U on the discounted electricity generating cost is given by Figure 7-5 with μ = 0,0299, σ = 0,1165 and a 10 % discount rate. In this case, the trend α has a positive value (see Table 7-1). It shows that IGCC is less expensive for annual utilisation above 4500 hours a year (which is normally the case for such plants).

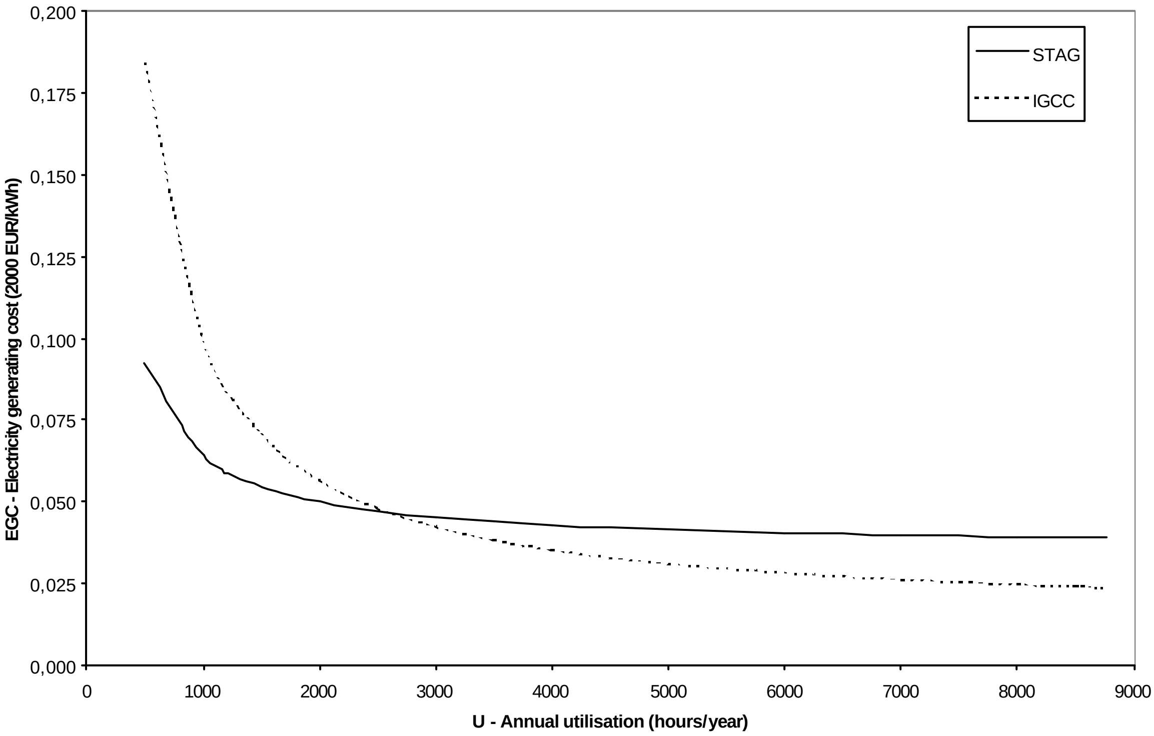

Figure 7-5 : influence of the capacity factor (μ = 0,0299, σ = 0,1165, i = 0,1)

Figure 7-6 shows the influence of the discount rate considered on the electricity generating cost difference between NGCC and IGCC. For a 5 % discount rate, minimal annual utilisation for IGCC drops to 2500 hours to be competitive with respect to NGCC power plant. For a 15% discount rate, the minimal value rises to 6500 hours.

Figure 7-7 shows the influence of the volatility in the case of a positive trend α. Consequently a reduced volatility is favorable to IGCC. Figure 7-8 shows the influence of the trend in the case of a high volatility σ.

These figures show the high influence of the stochastic parameters on the electricity generating costs calculated. Consequently, in comparison to a scenario approach, the stochastic modelling doesn't help to reduce the uncertainty. It's only providing a convenient method enabling comparison between historical observed volatility and the one induced by the choice of various scenarios.

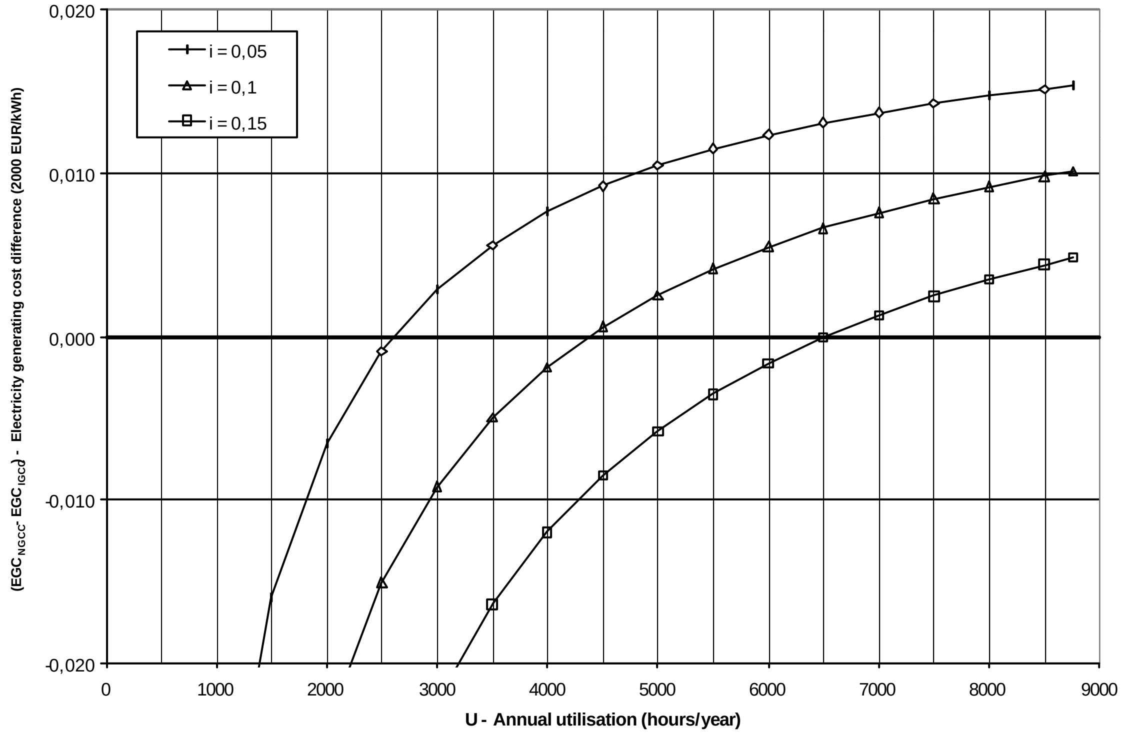

Figure 7-6 : influence of the discount rate i (μ = 0,0299, σ = 0,1165)

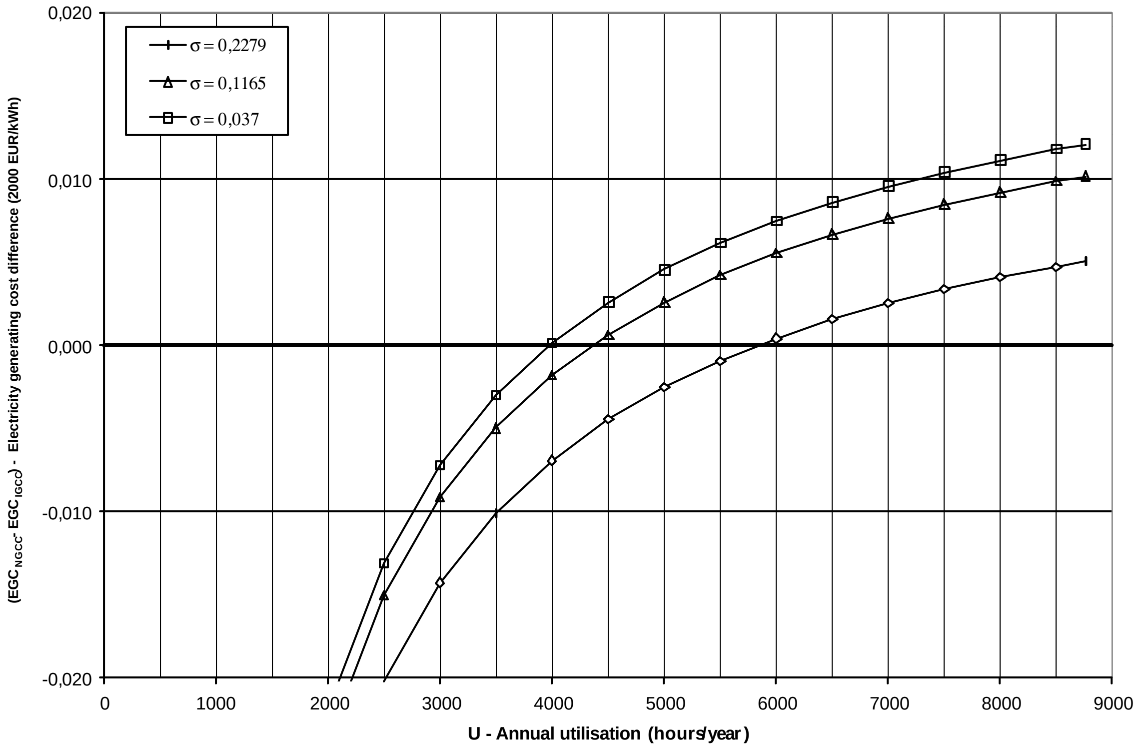

Figure 7-7 : influence of the volatility σ (μ = 0,0299, i =0,1)

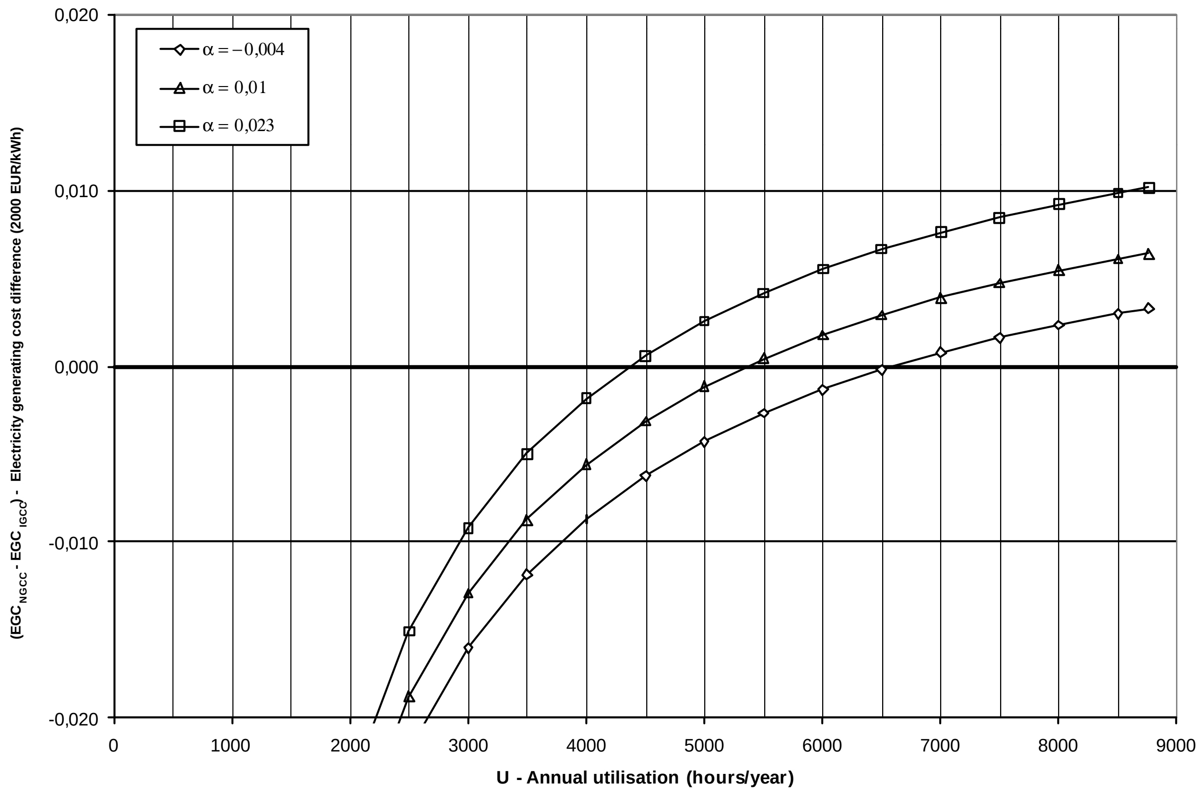

Figure 7-8 : influence of the trend α (σ = 0,1165, i =0,1)

7.2.2 Valuing flexibility

We consider now the possibility of a phased construction. Three new parameters could be considered, (1) the additional cost for STAG unit convertible into a IGCC power plant (fuel gas burner lines, space requirements, supply logistics,…) corresponding in financial term to the option cost (OC), (2) the net efficiency drop (ED) of such STAG units in comparaison with best available STAG units and finally (3) the repowering year. In this study, the potential increase of the power plant capacity when repowered to an IGCC has not been considered.

Figure 7-9 shows the discounted cash-flow during power plant lifetime with a repowering occuring in 2010. No additional costs and no efficiency drop have been considered for this calculation. GBM considered parameters are μ = 0,0029 and σ = 0,2279 with discount rate of 5%.

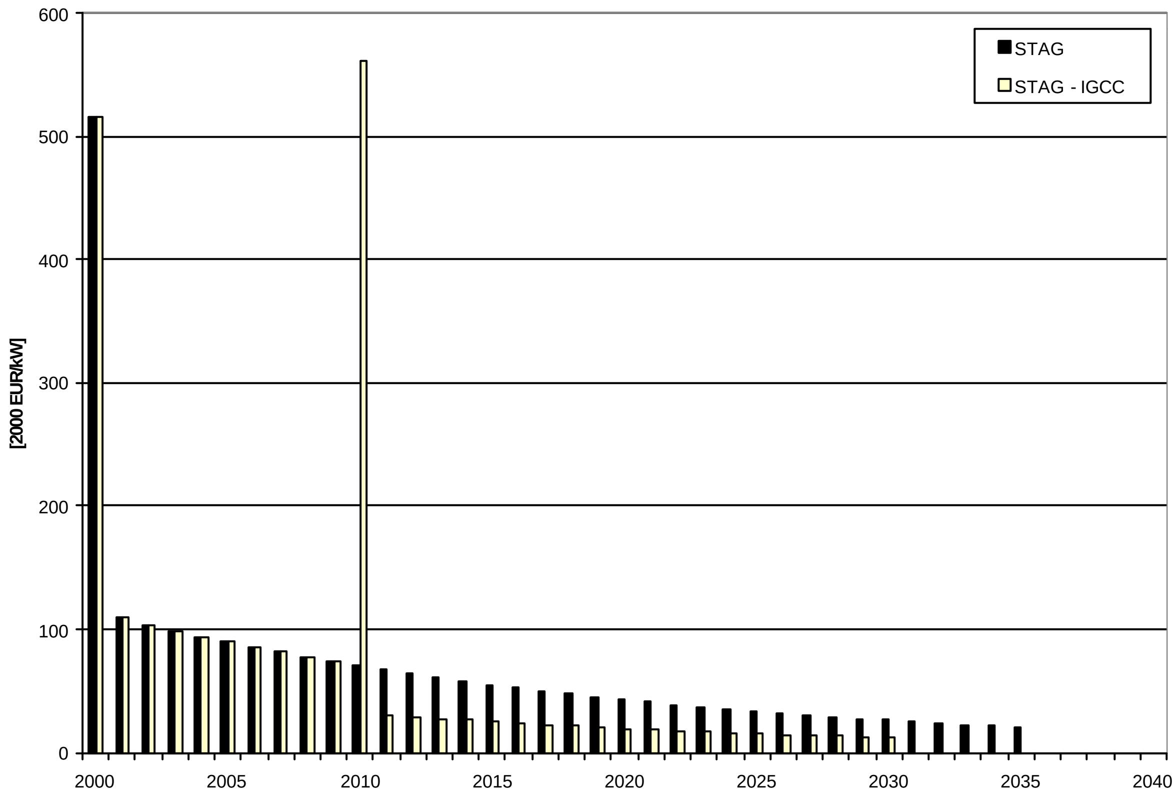

Figure 7-9 : discounted cash flow

In the conventional analysis, the decision criteria is the difference between the expected net present value (NPV) of two projects, (1) STAG investment, (2) STAG investment and IGCC conversion at a fixed repowering year. The second project has to be selected if the condition of equation (7) is fulfilled.

$$NPV_{2000} = (NPV_{NGCC} - NPV_{IGCC})_{2000}$$

$$NPV_{2000} = \left[\frac{I_{repowering}}{(1+i)^r} - OC\right] + \left[\sum_{t=r}^{n} \frac{E_{2000}\left[P(t)\right] - C(t)}{(1+i)^t}\right] > 0 \qquad (7)$$

In the conventional analysis, the natural gas price evolution used for calculation is based on the price value at the reference year. In the real options analysis, the conversion to an IGCC power plant will only be done if the NPV of the conversion evaluated at the repowering year is positive (fuel price evolution are based on fuel price level at repowering year) :

$$NPV_r = \left[\frac{I_{repowering}}{(1+i)^r}\right] + \left[\sum_{t=r}^{n} \frac{E_r\left[P(t)\right] - CP(t)}{(1+i)^t}\right] > 0 \qquad (8)$$

Equation 8 gives the thresold of the observed natural gas price at the repowering year, P_r^*, from which NPV_r becomes positive and repowering has to be decided. Figure 7-10 shows the evolution of P_r^* in the reference case.

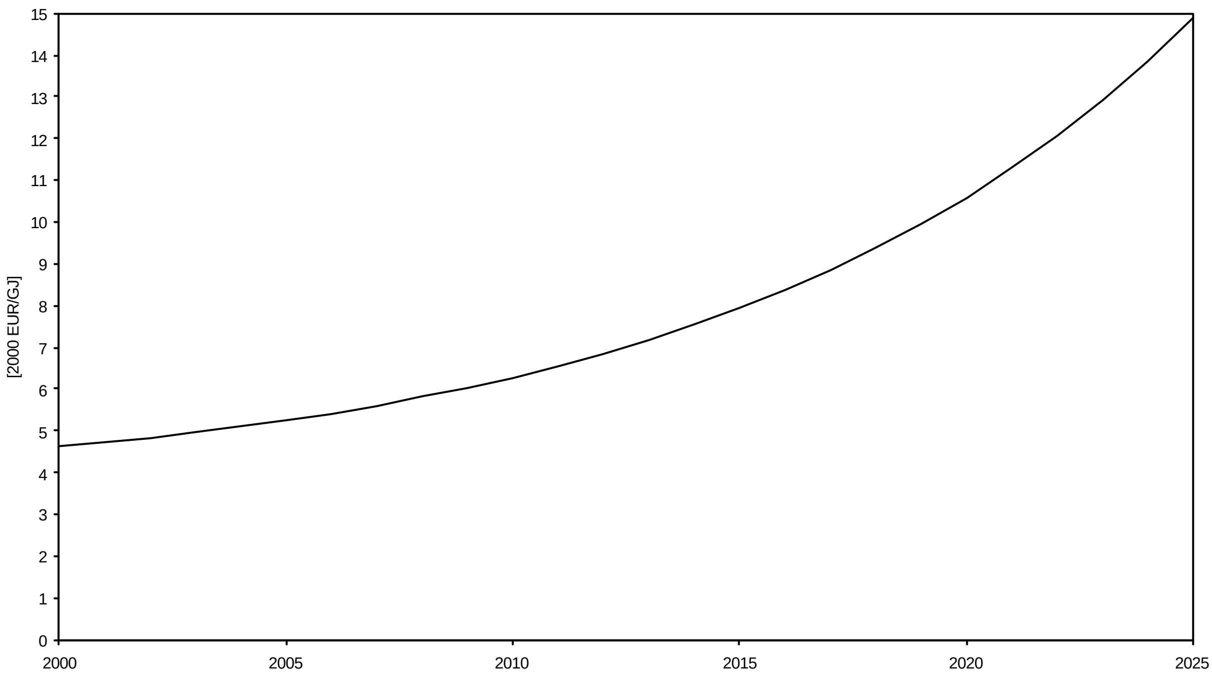

Figure 7-10 : Evolution of the minimum gas price required at repowering year (P_r^*) for IGCC conversion

Therefore, the decision criteria at the reference year in the real options analysis is given by the following equations:

$$ROV_{2000} = -OC + \frac{E_{2000}\left[\max(0,(NPV_{NGCC} - NPV_{IGCC})_r\right]}{(1+i)^r} \quad (9)$$

or

$$ROV_{2000} = -OC + \frac{\int_{P_r^*}^{\infty} (NPV_{NGCC} - NPV_{IGCC})_r \, f_r\left[P(r)\right] dP}{(1+i)^r} \quad (10)$$

Solution for equations 9 and 10 is given in [18].

The flexibility value linked to the possibility to switch fuel if gas price is too high is given by

FV = ROV – NPV (11)

Figure 7-11 shows the influence of the repowering year r on the NPV, ROV and FV for i=10%, OC = 0%, ED = 0%. In this case, the optimal repowering year is 2006.

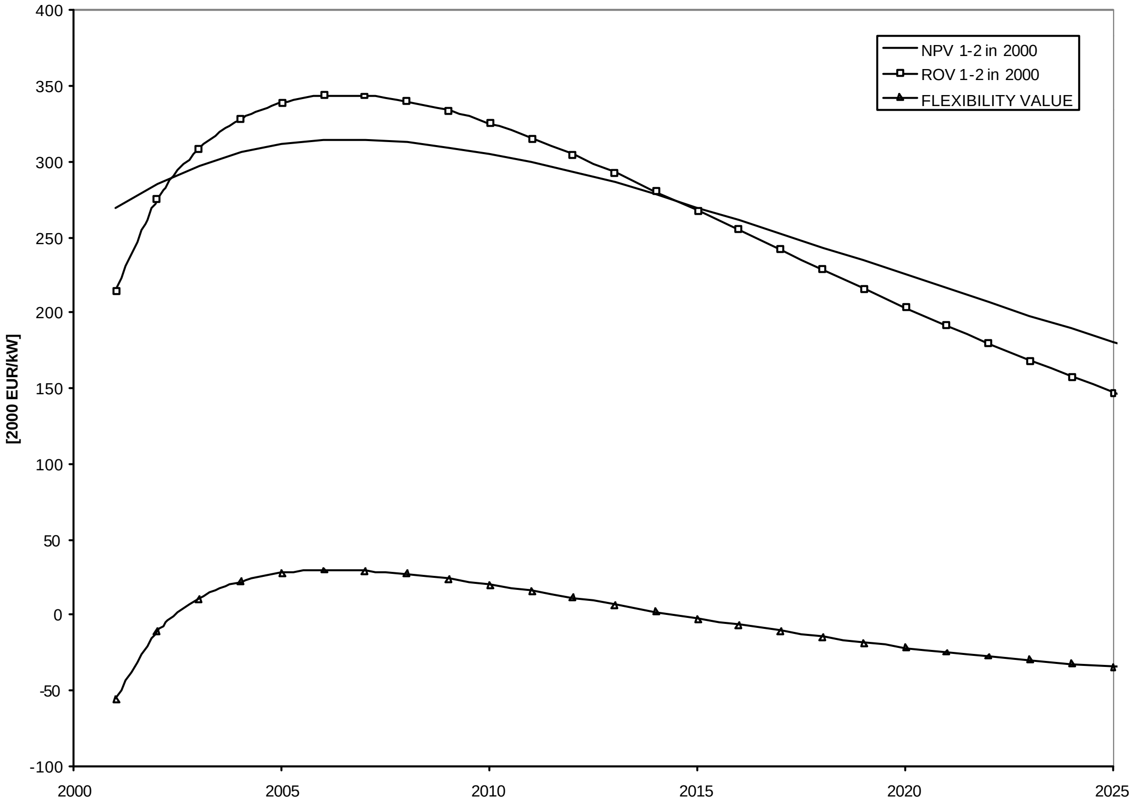

Figure 7-11 : Flexibility value gives the optimal repowering year

7.3 Conclusions

A simple method based on a stochastic modelling of the natural gas price evolution has been presented. By application of the real options theory, a monetary value of a phased construction flexibility is calculated as well as the optimal repowering year.

Nevertheless, further developments have still to be performed such as the use of more suitable stochastic processes for coal and gas prices evolution, a better integration of the technology evolution by the use of experience curves. Another major improvements of the method in this context of competition is to consider a stochastic process for the capacity factor or the use of the maximisation of the spark spread between electricity and gas as decision criteria instead of minimisation of the electricity generation cost. These improvements require more sophisticated calculation methods.

8 CONCLUSIONS AND FUTURE PROSPECTS

Fossil fuels and climate change

For period 1990-2010, progress in gas-fired and coal-fired power plants have allowed a specific CO2 emission reduction (g/kWh) of more than 15…20 %. In comparison to Kyoto targets, it seems to be significant but with respect to the climate change problem it seems to be insufficient. Consequently, new fossil fuel power plants require necessarily integration of CO2 separation systems. In this context, IGCC systems seems to be a very promising technology even if a large amount of R&D is still required.

Competitive and uncertain electricity market

Basic case studies based on conventional analysis or real options analysis show that for period 2000-2010 more efficient coal power plant complying with more stringent emission standards will be competitive with gas-fired combined cycle. This is mainly due to the positive trend for the gas price evolution predicted in most scenario.

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