SECTION I : EVALUATION OF THE CURRENT AND FUTURE PRODUCTION COST OF ELECTRICITY AND THE EXTERNAL COSTS

1. Introduction

We present here a static comparison of electricity production costs in 2010 in Belgium. Costs are divided in three categories: fuel costs, non-fuel costs (investment, operation and maintenance) and external costs (cost of air pollution, noise, greenhouse gases, ionising radiations, etc.). In a static comparison, these costs are aggregated into a single figure in BEF/kWh$_e$. This is the simplest way to compare the relative costs of different ways of producing electricity. There are other more refined ways to compare costs, but these are not discussed in this document (cf. contribution to Group I of 19 March 2000).

In this document, we start by explaining the methodology used. Next we present the main assumptions used for the fuel prices and for the external costs. In the last two sections we compare the costs of different new power plants, first the plants producing only electricity and then the combined heat and power technologies.

The main data source used are the reports of the different working groups of the Ampere Commission, complemented by the Markal/Belgium database built by KULeuven and VITO [1, 2, 4, 5]. Several meetings took place with Ampere experts to validate the whole dataset.

2. Methodology

2.1. What is a static comparison

The purpose of a static cost comparison is to estimate a single cost figure for different types of new power plants. This requires the aggregation of three categories of costs: fuel costs, non-fuel costs (investment, operation and maintenance) and external costs (cost of air pollution, noise, greenhouse gases, ionising radiations, etc.). Investment costs include all costs necessary to set up a power plant, including, among others, interest during construction, connection to the grid, and decommissioning in the case of nuclear energy

For a power plant producing only electricity the basic formula used to aggregate costs is:

Cost in BEF/kWh =

Fuel cost in BEF/GJ divided by the plant efficiency in kWh/GJ

+ *Other variable costs in BEF/kWh*
+ *Capital costs and other fixed costs expressed as annuity in BEF/kW divided by the expected maximum operating hours per year*
+ *External costs in BEF/kWh*

All costs are expressed before taxes and subsidies. Hence, they represent the opportunity cost for society of producing power rather than something else. We do not adjust the production costs for their labour content. This would only be justified if there were systematic unemployment for the skills involved in producing power plants. We accept that this is not the case.

The annuity is defined as the constant rental payment that has the same cumulative discounted value as the investment costs and the interest during construction. The annuity is a function of two elements: the expected economic lifetime of the plant and the interest rate.

Capital costs are translated into costs per kWh by using a maximum expected hours of operation per year. The maximum expected number of hours of operation takes into account the planned and unplanned unavailability of the power plant. For wind and hydro powerplants, the maximum expected number of hours of operation takes also into account the availability of wind or water power. An alternative computation technique is to use an identical number of hours for all power plants, as is sometimes done for base load plants. If one makes a pure comparison of power production costs without paying attention to the contribution to reserve capacity or the role of a power plant in the whole system as is done here, the use of a maximum number of hours of operation is more appropriate.

External costs represent the costs that power production imposes on society and that are not included in the fuel, capital or variable costs and are not taken into account by the electricity generators. The most important external costs are the environmental costs. In order to be able to compare different types of power plants, a translation of different types of environmental damages into a common denominator is necessary. In addition, this denominator needs to be a monetary one, in order to compare cleaner but more expensive production techniques to dirtier but cheaper techniques. When external costs are left out of the cost aggregation, all plants comply with current or expected environmental regulation. As this regulation differs among different technologies and some technologies are cleaner, the cost comparison of technologies would pay no attention to the environmental advantages of some types of plants.

For combined heat and power plants, a different approach is used. In order to compare the costs of electricity produced by a CHP plant with electricity produced by a plant producing only electricity we start from the following principle: it is only cost-effective to use a CHP plant if

Total Cost of CHP plant use *< cost of electricity produced separately*
+ cost of heat produced in a separate plant

Therefore electricity produced by CHP is only more cost-effective than electricity produced by a plant producing only electricity, if

Total cost of CHP plant use – cost of heat produced in a separate plant
< cost of electricity produced separately

This is a very simple cost comparison of the combined and non-combined production techniques that is sufficient for our purposes. The costs in the previous expression include fuel costs, capacity costs and external costs.

The comparison of costs will only be correct for those hours of operation that there is a sufficient demand for heat. The maximum expected number of hours of operation will therefore be different for the different sections of the heat market. We make a distinction between the CHP units that supply the residential and service heat market (max 50% of total number of hours) and the CHP units supplying the industrial market where a utilisation rate of 80% has been assumed.

However, because of the difficulty to assess the various parameters in this approach (the heat temperature produced by each process, the exergy contents, the distribution costs, etc.), it should only be used to compare electricity costs of different cogeneration units between themselves. Comparing electricity costs between cogeneration plants and other power plants should be considered only with the greatest care.

2.1.1. Caveats

The static comparison of electricity production costs is useful to know orders of magnitude of production costs. It is not the appropriate technique to compute optimal prices for electricity or for heat. The static comparison is a simple and transparent technique but neglects some important factors:

- The contribution to guaranteed power: this is an important cost factor to be added for cogeneration, wind and solar power-plants whose production is not fully driven by the needs of the total electricity demand – during the peak periods or during outage periods, capacity has a much higher value than during the off period. Our comparison favours therefore too much the production with cogeneration whose production is determined by heat demand, wind and sunshine conditions.

- Some plants will not be used at full capacity during their whole lifetime because the utilisation of a plant will be determined by total demand and the running costs of the other available production units (merit order).
- The different technologies are not yet optimised in function of their external costs; most technologies that are analysed do minimise their direct production cost and try to meet their present emission regulations. If they tried to minimise the total of direct production costs and external costs, most technologies would reduce their external costs (by lowering emissions) at the expense of an increase in production costs.
- The potential total capacity that can be installed of some types of power plants (wind and other renewables, CHP) is obviously very limited in Belgium. Costs are only compared for the locations with the lowest costs

2.1.2. Assumptions on fuel prices

The fuel costs used are in line with the scenarios developed by Working Group B. Fuel costs have been estimated for 2010, excluding taxes but including delivery and other miscellaneous costs. All prices and costs are expressed in constant 2000 Belgian francs. For the electricity producers, low sulphur fuel oil, will cost 160 million BEF/PJ in 2010. Diesel will cost 233 million BEF/PJ, natural gas 143 million BEF/PJ[1], and coal 73 million BEF/PJ (2102BEF/ton). This is based on the assumptions that coal prices will stay almost constant in the future, an oil price of $24.3 per barrel[2], and a gas price following oil prices. When hydrogen is produced separately (for fuel cells), we have assumed it would be produced from natural gas, in specialised units, at a cost of 293 million BEF/PJ [2].

In the long run, we expect oil (and gas) price to steadily increase (up to $31 per barrel in 2020 and $37.2 per barrel in 2030), while coal price should remain stable. We have assumed the following prices in 2030: 224 million BEF/PJ for low sulphur oil, 335 million BEF/PJ for diesel, 241 million BEF/PJ for natural gas and 76 million BEF/PJ for coal. The cost competitiveness of coal power plants will thus progressively improve relatively to gas/oil power plants.

For nuclear fuel, we assumed the same values as those used by VITO in a recent study for Electrabel. VITO estimates that the cost of fuel for a PWR will be 105 million BEF/PJ_e in 2010 and 128 million BEF/PJ_e in 2030. AP600 have a slightly lower efficiency than PWR (31% against 33%). Consequently, the cost of fuel for these power plants is slightly higher than for PWR, at 112 million BEF/PJ_e in 2010. For MHTGR, because of their higher efficiency, the fuel costs are 45% lower than for PWR. This estimate includes the processing of fuel wastes.

2.1.3. Assumptions on discount rate

A real discount rate of 5% has been used. This corresponds to the long term borrowing rate of the government on international capital markets. We have chosen this rate because it corresponds to the needs of an analysis at a horizon of 40 years. Because the projects discussed here are small compared to the supply of funds on the international capital market, one does not have to take into account crowding out effects. The interest rate used in

[1] CIF prices at the border are slightly lower, at 129 BEF/GJ, or 124 BEF/MBTU (GHV) in 2010.

[2] In current prices. Source: CO_2 study for the federal Ministry of Environment. This assumption is close to the scenarios of J.-P.Pauwels and of the IEA forecast.

practice can be different and varies in function of the cost of funds for the investor and of the degree of risk.

2.1.4. Assumptions on external costs

External costs have been taken from an update of the European Commission DG Research study: *ExternE, Externalities of Energy*, volume 10: National implementation, Table 5.18 (values for Belgium are shown on Table 1), using the ExternE 1998 methodology and ExternE 2000. This study provides estimates of external costs of energy production for emissions of SO_x, NO_x, PM_{10}, and greenhouse gases (GHG: CO_2, N_2O, CH_4), ionising radiations and other nuisances. ExternE assesses external costs of the entire life cycle of electricity. External costs estimated thus include a number of components, such as the costs due to:

- noise
- visual intrusion and visibility losses (e.g. smog)
- risks of major accidents
- emissions and health risks during the operation of the power plant
- emissions and health risks during all stages of fuel extraction, preparation and transport
- emissions and health risks during the construction of the power plant, and for the preparation and the transport of the construction materials

For greenhouse gases (measured in CO_2 equivalent) we used the middle estimate provided by ExternE, with a 3% long-term discount rate, at 741 BEF[3] per ton of CO_2 (see Table 1).

For wind energy, we have used an estimate provided by VITO for Belgian sites. External costs for windmills are estimated at 0.04 BEF/kWh at the seaside and for offshore wind farms, and at 0.12 BEF/kWh for inland sites. The external costs of wind energy are mostly (more than 95%) created during the manufacturing of the equipment.

The ExternE study also provides external costs for nuclear electricity generation. We used the estimate over 10,000 years, with 0% discounting, as recommended in the ExternE report.

Emission factors are shown on Table 2 for technologies producing only electricity, and in Table 7 for cogeneration technologies. They were taken from the Markal database and reviewed by experts of the Ampere Commission.

[3] This is an estimate based on expected damages due to climate changes in the world. The value suggested is somewhat lower than the prices expected for internationally traded CO_2 permits and much lower than the marginal costs of reaching the CO_2 emission target in Belgium without trade (approximately 1830 BEF/ton CO_2) in a recent study with Markal for the federal Ministry of the Environment.

Table I1: External costs of electricity generation

	Coal & Oil (ExternE 98)	Gas (ExternE 98)	New Values (all fuels) (ExternE 2000)
Fossil fuel power generation			
SO_2 (BEF/ton)	500,000	469,000	247,000
NO_x (BEF/ton)	537,000	538,000	206,000
PM_{10} (BEF/ton)	1,011,000	-	494,000
Occupational, noise & others (BEF/kWh_e)	0.0111	0.0016	No change
Other stages (BEF/kWh_e)	0.0284	0.0029	No change
Radionuclides, all stages (BEF/kWh_e)	**Nuclear (open)**	**Nuclear (closed)**	
0% discounting, 10,000 years	0.165	0.165	0.028 radio nucl. 0.011 for GHG
0% discounting, 100,000 years	0.931	0.721	NA
3% discounting, 100,000 years	0.004	0.004	NA
Wind turbines (BEF/kWh_e)			**Inland / coastal & offshore**
Power generation and other stages			0.12 / 0.04
Greenhouse gases, all stages (BEF/ton CO_2 equivalent)			
Low	157		No change
Mid-3% discount	741		No change
Mid-1% discount	1,895		No change
High	5,726		No change

Sources: [3] ExternE (1998), vol. 10, National Implementation, table 5.18, p.104, and table 7.11, p179. Data in this table are in constant 2000 BEF, computed by KULeuven from the 1995 constant ECUs of the original Table. ExternE 2000 data were obtained from VITO, as well as the data for wind turbines.

Table I 2: Emission factors in 2010
g/kWh_e

	SO_2	NO_x	PM_{10}	CO_2	N_20	CH_4	CO_2 eq
Pulverised coal (SC)	0.75	0.60	0.051	792	0.04	0.01	805
Pulverised coal (ASC)	0.30	0.16	0.048	752	0.04	0.01	765
Pulverised coal (USC)	0.27	0.14	0.043	680	0.04	0.01	691
IGCC	0.20	0.17	0.005	827	0.04	0.00	841
Kerosene gasturbine	0.82	2.51	0.000	808	0.10	0.00	839
Gas gasturbine	0.00	1.22	0.000	505	0.03	0.05	514
STAG power plant	0.00	0.36	0.000	337	0.02	0.04	343
Municipal waste incinerator	0.06	0.7	0.005	540	0.05	0.00	545

Source: [5] Markal database (except for incinerators: Prof. De Ruyck)

2.2. Cost of Separate electricity production

We have focused on the technologies which could be used in the construction of new power plants, rather than on the description of the existing power plants that will anyway cease to operate in the coming decade. In the case of coal, for example, only super critical and IGCC power plants are included in the report.

Table 3 and Chart 1 present the cost of electricity production for the main technologies that could be used in 2010. The column “Total 1” accounts for all fuel and non-fuel production costs. In addition, “Total 2” includes external costs.

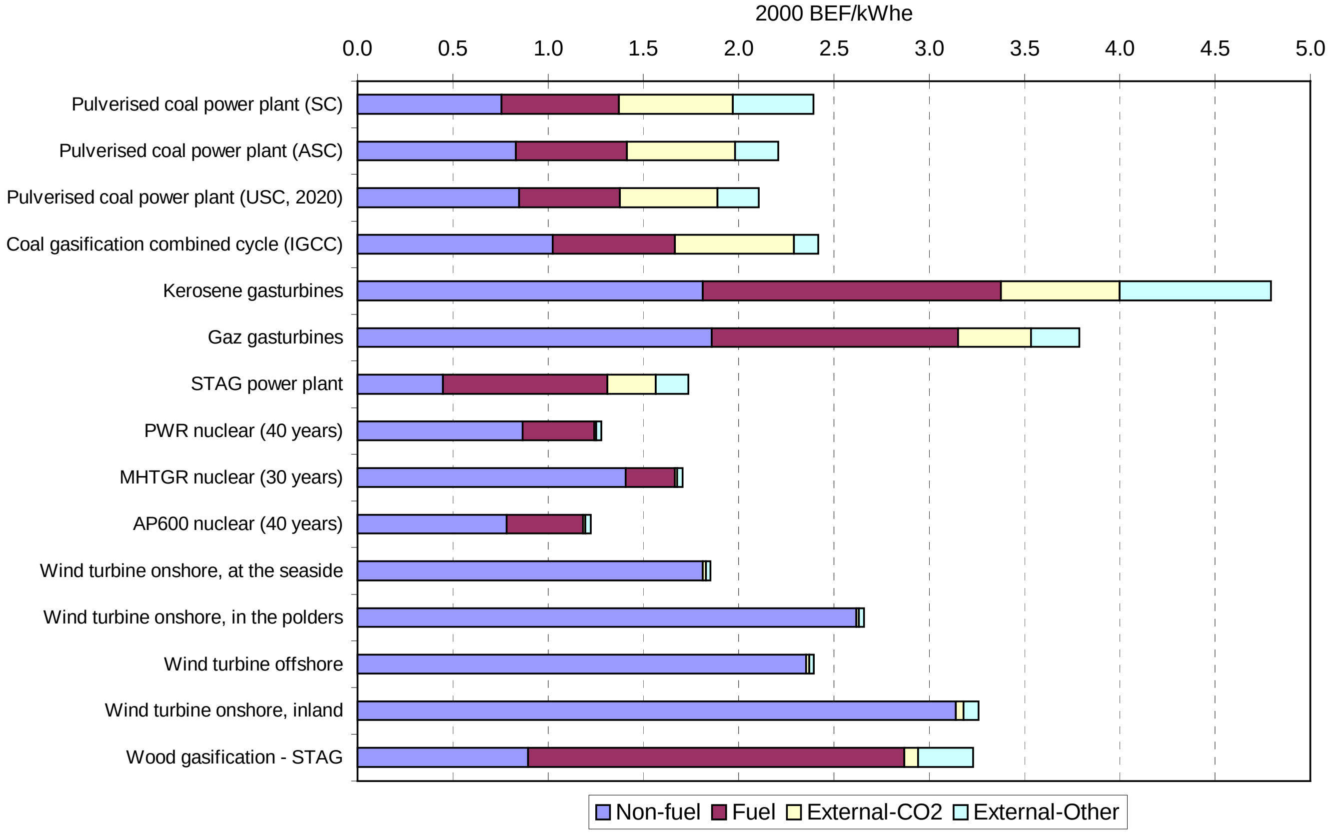
Table I 3: Cost of electricity production by technologies producing only electricity in 2010 in constant 2000 BEF/kWh$_e$

	Cost (non fuel)	Fuel cost	Total 1	External cost / CO2	External cost / other	Total 2
Pulverised coal (SC)	0.76	0.61	1.37	0.60	0.37	2.34
Pulverised coal (ASC)	0.83	0.58	1.41	0.57	0.23	2.21
Pulverised coal (USC, 2020)	0.85	0.53	1.38	0.51	0.22	2.10
IGCC	1.03	0.64	1.67	0.62	0.13	2.42
Kerosene gasturbines	1.81	1.57	3.38	0.62	0.76	4.76
Gas gasturbines	1.86	1.29	3.15	0.38	0.25	3.79
STAG power plant	0.45	0.86	1.31	0.25	0.17	1.74
PWR nuclear (40 years)	0.87	0.38	1.24	0.01	0.03	1.28
AP600 nuclear (40 years)	0.78	0.40	1.18	0.01	0.03	1.22
MHTGR nuclear (30 years)	1.41	0.26	1.67	0.01	0.03	1.70
Wind turbine onshore, seaside	1.81	0.00	1.81	0.02	0.02	1.85
Wind turbine onshore, polders	2.62	0.00	2.62	0.02	0.02	2.66
Wind turbine offshore	2.35	0.00	2.35	0.02	0.02	2.39
Wind turbine onshore, inland	3.14	0.00	3.14	0.04	0.08	3.26
Wood gasification – STAG	0.90	1.97	2.87	0.07	0.29	3.23
Waste incinerators	0.59	1.17	1.76	(0.41)	(0.20)	(2.38)

Chart I 1: Cost of separate electricity production in 2010 in constant 2000 BEF/kWh$_e$

We present hereafter the main technologies considered for separate electricity production.

2.2.1. Coal technologies



2.2.1.1 Pulverised coal power plant

This category includes the newest coal power plant. Coal technology is evolving towards higher temperatures and pressures, and we model this technical progress with three categories: super critical (SC), advanced supercritical (ASC) and ultra supercritical (USC) power plants.

Following discussions with Ampere experts, and based on the workgroup D report [7], we have adopted the following parameters,

Table I 4: Assumptions for future coal power plants

	Available in	**Efficiency**	**Investment cost**
Super critical (SC)	2000	43%	47,000 BEF/kW
Advanced SC	2010	47% to 48%	50,000 BEF/kW
Ultra SC	2020	47% to 52%	52,000 BEF/kW

For the three technologies, utilisation rate is 84% (7358 hours per year) and lifetime 30 years. A typical capacity for such a power plant is 300 MW, although larger plants are possible.

For SO_x and NO_x removal, a wet gypsum and a selective catalytic reduction unit are assumed in the supercritical power plants. For advanced and ultra supercritical power plants, we have assumed more advanced abatement technologies, which decrease efficiency by 3.7% (thus by about 1.8 percentage points) relatively to the figures in Table 4, but cut NO_x emissions by half and emissions of SO_x in three and increase the investment cost by 1.7%.

The electricity production costs for these three technologies are around 1.4 BEF/kWh, and 2.2 BEF/kWh including external costs.

2.2.1.2 Coal gasification combined cycle (IGCC)

A 260 MW IGCC power plant is considered. We assume that this technology will be available in 2010, for an investment cost of 67,000 BEF/kW, which will progressively decline to 60,000 BEF/kW in 2030. Efficiency will increase from 41% to 48% over the same period. We also assume that IGCC power plants have a lifetime of 25 years and operate 83% of the time (7271 hours per year).

We assumed that turbine such as General Electric type H turbines would be used, with a Claus Scott unit for de-SO_x. Advanced combustion techniques (injection of nitrogen to reduce flame temperature and saturation of the syngas with water before the combustion chamber) allow very low levels of NO_x emissions.

Total production costs for an IGCC power plant should be at 1.67 BEF/kWh in 2010 (2.42 including external costs).

2.2.2. Nuclear technologies

We consider here three types of nuclear power plants. The PWR (the current technology in Belgium), the AP600 advanced light water reactor, available from 2005 onwards and the modular high-temperature gas-cooled reactor (MHTGR), available from 2010 onwards. We have estimated the costs of the two first reactors for a lifetime of 40 years. The lifetime of MHTGR is constrained to 30 years by the lifetime of the heliumgasturbine used in these powerplants.

In theory, external costs per kWh should be lower for the longer lifetime, as the damage caused by the construction of the power plant, for example, would be spread over more kWh. However, some other external costs (linked to fuel preparation and transport for example) will be proportional to production. Lacking detailed information on these, we used the ExternE figures in all cases.

2.2.2.1 Large scale pressurised water reactor (PWR)

It is particularly difficult to find accurate data on the cost of setting up a large scale PWR power plant. We assumed a slight decline of investment costs for PWR, from 68,000 BEF/kW in 2010 to 65,000 BEF/kW in 2030. Investment costs for nuclear power plants included IDC, decommissioning, first core, simulator and connection to the grid.

The production capacity of a large scale PWR is around 1,300 MW. We assumed an operating rate of 85% (7446 hours per year). For a lifetime of 40 years(requested life time without major replacements as expressed in the “European Utility Requirements” (EUR)), total cost of production is then 1.24 BEF/kWh$_e$ in 2010. With external costs included, total costs amount to 1.28 BEF/kWh$_e$ in 2010.

2.2.2.2 AP600 nuclear power plant

The passive advanced light water reactor, such as Westinghouse's AP600 (a small scale passive PWR), should rapidly become available. We have assumed [8] a lifetime of 40 years and an availability of 85% (7446 hours per year). Investment costs are presently at 85,000 BEF/kW. for a first kind of reactor. This investment cost is expected to decline to 75 000 BEF/kW (a bit higher than a large scale PWR because of the scale effect). One characteristic of these passive security reactors is their low operating and maintenance costs, due to the reduced number of equipment needed. We have assumed operation and maintenance costs would be 50% lower than for a PWR.

Efficiency of AP600 is about the same as for PWR (31% against 33%). Consequently, the cost of fuel for these power plants is slightly higher than for PWR, at 0.40 BEF/kWh in 2010.

Total cost of production is then 1.18 BEF/kWh$_e$ in 2010 . External costs add 0.04 BEF/kWh$_e$, for a total of 1.22 BEF/kWh$_e$ in 2010.

2.2.2.3 MHTGR nuclear power plant

The investment cost of modular a high-temperature gas-cooled reactor (MHTGR) is expected to be about 120,000 BEF/kW in 2010 (demonstration plant, first of a kind). It will however decrease over time, and is expected to reach 70,000 BEF/kW in 2030. The typical size of such reactor could be 800 MW$_e$. The lifetime of these reactors is estimated at 30 years (because of the presence of a gas turbine) and their availability at 85% (7446 hours per year). MHTGR power plants are more efficient than PWR's (48% instead of 33%). They use 31% less fuel for the same output.

Total cost of production is then 1.67 BEF/kWh$_e$ in 2010 and declines to 1.28 BEF/kWh$_e$ in 2030. External costs add 0.04 BEF/kWh, for a total of 1.70 BEF/kWh$_e$ in 2010.

2.2.3. Gas and oil technologies

2.2.3.1 Gas gasturbines (single cycle)

We consider here single cycle gas turbines of about 250 MW. They have an efficiency of 40%. These power plants are mostly used at peak time, and are thus used only a small fraction of the time. We have assumed a usage rate of 1000 hours per year, probably an upper limit. Investment cost is at 15,500 BEF/kW, and they will last 15 years.

For a gas turbine, production cost is at 1.86 BEF/kWh$_e$ (excluding fuel). Including fuel costs, producing a kWh$_e$ costs 3.15 BEF in 2010 and 4.03 BEF in 2030. Gas turbines are equipped with low NO_x burners. With external costs, production costs raise to just over 3.79 BEF/kWh$_e$ in 2010.

2.2.3.2 STAG power plant (combined cycle)

We consider combined cycle gas power plant of 460MW. The investment cost for a STAG is now 20,000 BEF/kW, and this amount is not expected to change in the future. The lifetime of a STAG is estimated at 20 years.

Efficiency of STAG power plants rises progressively from 55% in 1995 to 65% in 2030. For emission reduction purposes, they are equipped with low NO_x burners.

Excluding fuel costs, and assuming a usage rate of 7490 hours per year (85.5%), the cost per kWh_e is BEF 0.45 in 2010. If we include fuels, production cost rise from 1.31 BEF/kWh_e in 2010 to 1.79 BEF/kWh_e in 2030. With external costs, we reach 1.74 BEF/kWh_e in 2010.

2.2.3.3 Kerosene gasturbines

The turbine are very similar to gas gasturbines. Apart from a lower efficiency (at 33%), other parameters are identical. Kerosene-fuelled turbines have a low investment cost, but a high fuel cost. They are thus generally used as reserve units, and operate only at peak times. We assumed a usage rate of 1000 hours per year.

There is no specific emission abatement device on this power plant. Total production costs are 3.38 BEF/kWh_e in 2010, and 4.79 BEF/kWh_e including external costs.

2.2.4. Wind power

Turbines now typically have a capacity of about 1 MW. Following workgroup F, we have considered the following wind conditions and usage rates: 3,500 hours per year offshore, 2,600 hours on the coastline, 1800 close to the coastline (for example the polders area, within 15km of the coast) and 1,500 hours inland, with a lifetime of 20 years in all cases. After discussions with Prof. De Ruyck, annual operation and maintenance costs have been assumed to amount to 3.75% of the capital cost.

The investment cost equals 40,000 BEF/kW for onshore wind turbines, and 70,000 BEF/kW offshore (workgroup F). The direct cost per kWh is the lowest for wind turbines along the coastline, at 1.81 BEF/kWh. Offshore windfarms produce electricity at a cost of 2.35 BEF/kWh. In the Polders, production cost increases to 2.62 BEF/kWh, and for inland turbines, it reaches 3.14 BEF/kWh.

External costs are small for wind farms. According to VITO, they amount to 0.04 BEF/kWh_e for sea/coastal sites, and 0.12 BEF/kWh for inland sites. This is mostly due the emissions generated during the production of the wind turbines. Visual intrusion and ecosystem damages (to fishes or birds, for example) have not been estimated in ExternE because they are small or because no data are available.

2.2.5. Energy from biomass

We consider here a wood gasification unit coupled with a STAG, of a capacity of 50MW (see [1]). The cost of this technology (56,000 BEF/kW) is substantially higher than the cost of a natural gas-fired STAG, because of the cost of the gasification unit. We assumed a usage rate of 82.5% (7,227 hours per year), and a lifetime of 25 years.

Including fuel costs (at 1.97 BEF/kWh), the cost of electricity generation from this technology is 2.87 BEF/kWh (or 3.23 BEF/kWh if we include external costs).

2.2.6. Municipal waste incinerator

For waste incineration, we have considered only the additional cost of setting up an electricity producing facility on an existing (or planned) waste incinerator. The reason for this is that waste incinerators are only built for waste management purposes, and electricity is only a by-product that helps financing the operation.

We have computed the external costs as if all the emissions of the incinerator were attributed to electricity production. It could however be argued that these costs should be attributed to waste incineration only, and not to electricity production. To underline this point, we have indicated the external costs in brackets. Anyway, as production capacity of this technology is limited by the availability of waste, this technology only contributes marginally to electricity production (currently, municipal waste incineration contributes to about 1% of electricity production in Belgium).

Emission factors have been communicated by Prof. De Ruyck, based on the IVAGO incinerator (including the impact of dioxin emission standards). Following the Ampere Group F report, municipal wastes contain 70% of bioorganic, renewable, materials. We have thus only counted 30% of total CO_2 emissions.

Without external costs, the electricity production cost of this technology is 1.76 BEF/kWh in 2010. External costs would add 0.61 BEF/kWh.

2.3. Cost of electricity production with cogeneration

Here we present the main technologies considered for production of electricity with cogeneration.

A large number of cogeneration technologies are available, based on gas turbines (with single or combined cycle), gas or diesel engines, fuel cells and biomass gasification.

We consider three different types of heat, following temperature/pressure and usage:

- high temperature steam for industry (HT)
- low temperature steam for industry (LT)
- space heating (SH) for the residential sector and services

Comparing the electricity cost of technologies producing both heat and electricity raises some problems, as different technologies produce different splits between heat and electricity. In addition, the different types of heat do not necessarily have the same value per joule. It is thus difficult to allocate the production costs to electricity or heat. Below, we attempt to compare the costs of electricity produced in cogeneration power plants using the method of the avoided heat production cost (cf. earlier section 1.2). For the reasons mentioned above, this should be only considered as indicative, and no direct comparison should be done between cogeneration plants and other electricity power plants.

In a first step, we present the production cost for each technology, regardless of their heat production (table 5). This provides the basic information on each type of power plants.

Table I 5: Cost of electricity production in cogeneration power plants in 2010 (assuming the value of heat equals 0) in constant 2000 BEF/kWh$_e$

	Cost (non fuel)	Fuel cost	Total 1 (no ext. costs)	Total 2 (with ext. costs)	H/P
Gas turbine, HT	0.92	2.03	2.95	3.97	2.20
STAG (nat. gas), HT	0.57	1.32	1.89	2.56	1.00
Fuel cells (hydrogen), HT, 2015	1.85	1.99	3.85	4.62	0.54
Fuel cells (nat. Gas), HT, 2015	1.88	1.03	2.91	3.57	0.55
Back pressure turbine, LT	1.29	2.35	3.64	4.81	3.00
Gas engine (1 MW), LT	1.00	1.44	2.43	2.94	1.50
Gas engine (650 kW), SH	1.11	1.50	2.61	3.15	1.60
STAG (nat. gas), SH	0.93	1.14	2.06	2.63	1.32
Diesel engine, SH	0.63	2.13	2.76	6.01	1.15
Hay/Straw/Misc. gasification, SH	3.84	8.60	12.44	12.69	1.80
Wood gasification, SH	3.06	3.21	6.27	6.49	1.80
Fuel cells plant (hydr.), SH, 2015	1.96	1.97	3.93	4.54	0.54
Fuel cells plant (nat. gas), SH, 2015	1.96	1.02	2.98	3.64	0.55
Fuel cells (hydrogen), SH	2.82	2.07	4.89	5.70	0.54
Fuel cells (nat. Gas), SH	2.86	1.29	4.16	4.98	0.55

Source: Markal database.
Note: HT: high temperature heat for industry,
LT: low temperature heat for industry;
SH: space heating

In a second step, we allocate the production costs to heat and electricity. To do this, we assume that the heat produced by a cogeneration unit replaces heat produced by a gas boiler. In the case of low temperature (heat for industry and for residential/services), we assumed that the cost per gigajoule of heat delivered was 0.291 BEF/kWh$_{th}$, and in the case of high temperature heat, 0.407 BEF/kWh$_{th}$. The corresponding emissions are, for low temperature heat, 202 g/kWh$_{th}$ for CO_2 and 0.46 g/kWh$_{th}$ for NO_x, and for space heating, 234 g/kWh$_{th}$ for CO_2 and 0.54g/kWh$_{th}$ for NO_x.

To obtain our estimate for the cost of electricity, we take the cost per kWh$_e$ from Table 5 (with a zero value for heat). We then deduct from this cost per kWh$_e$ a credit of 0.291 francs per kWh$_{th}$ of heat produced (equal to the H/P ratio, which gives the amount of heat produced with each kWh of electricity) in the case of low temperature heat for industry, residential and service sector and 0.407 BEF per kWh$_{th}$ of heat produced in the case of high temperature heat. The cost reduction has been allocated proportionally between fuel and non-fuel costs.

To compute the external cost linked to emissions of a cogeneration plant that can be allocated to the electricity production, we first attributed all emissions to electricity production. Then, we deducted the emissions caused by the gas boiler to produce the same amount of heat than that co-generated by the power plant (again the H/P ratio gives the amount of heat produced for each kWh of electricity).

In some cases, because the emissions of the cogeneration plant are very low (for example, no CO_2 emissions for biomass), and in any case much lower than the conventional gas boiler, the external cost can become negative.

We have assumed a utilisation rate of 50% for cogeneration plants supplying the residential and services sector, and 80% for cogeneration plants supplying industries.

Emission factors (per kWh of electricity) are given in Table 7.

Table I 6: Cost of electricity production in cogeneration power plants in 2010 in constant 2000 BEF/kWh$_e$ (after deduction of avoided heat generation costs in a gas boiler)

	Cost (non fuel)	Fuel cost	Total 1	External cost / CO2	External cost / other	Total 2
Gas turbine, HT	0.64	1.41	2.05	0.28	0.18	2.52
STAG (nat. gas), HT	0.45	1.04	1.48	0.25	0.16	1.90
Fuel cells (hydrogen), HT, 2015	1.75	1.88	3.63	0.29	0.35	4.27
Fuel cells (nat. Gas), HT, 2015	1.73	0.95	2.69	0.23	0.29	3.21
Back pressure turbine, LT	0.98	1.79	2.76	0.26	0.16	3.19
Gas engine (1 MW), LT	0.82	1.18	2.00	0.20	-0.07	2.12
Gas engine (650 kW), SH	0.91	1.23	2.15	0.17	-0.11	2.21
STAG (nat. gas), SH	0.75	0.93	1.68	0.12	0.07	1.86
Diesel engine, SH	0.55	1.87	2.42	0.33	2.59	5.34
Hay/Straw/Misc. gasification, SH	3.68	8.24	11.92	-0.24	-0.05	11.63
Wood gasification, SH	2.80	2.94	5.75	-0.24	-0.07	5.44
Fuel cells plant (hydr.), SH, 2015	1.88	1.89	3.77	0.19	0.26	4.22
Fuel cells plant (nat. gas), SH, 2015	1.85	0.97	2.82	0.21	0.28	3.31
Fuel cells (hydrogen), SH	2.73	2.00	4.73	0.29	0.36	5.38
Fuel cells (nat. Gas), SH	2.75	1.24	4.00	0.30	0.36	4.66

Note: HT: high temperature heat for industry,
LT: low temperature heat for industry;
SH: space heating

Chart I 2: Cost of electricity production in cogeneration power plants in 2010 in constant 2000 BEF/kWh$_e$, adjusted for heat production

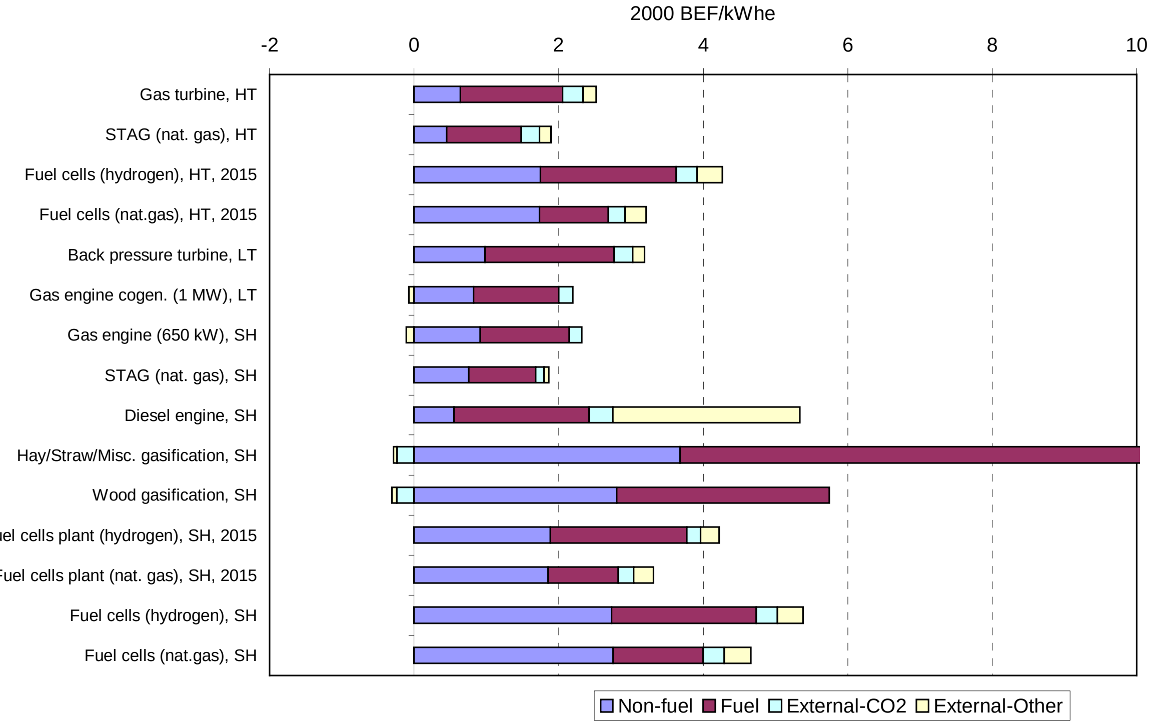


Table I 7: Emission factors in 2010 (g/kWh$_e$)

	SO_2	NO_x	PM_{10}	CO_2	N_20	CH_4	CO_2 eq
Gas turbine, HT	0.00	1.92	0.00	792	0.04	1.27	832
STAG (nat. gas), HT	0.00	1.25	0.00	516	0.03	0.83	542
Fuel cells (hydrogen), HT, 2015	0.00	1.95	0.00	476	0.00	0.71	491
Fuel cells (nat. gas), HT, 2015	0.00	1.66	0.00	404	0.02	0.61	423
Back pressure turbine, LT	0.00	2.23	0.00	918	0.05	1.47	964
Gas engine (1 MW), LT	0.00	0.36	0.00	561	0.03	0.13	573
Gas engine (650 kW), SH	0.00	0.38	0.00	585	0.03	0.88	614
STAG (nat. gas), SH	0.00	1.07	0.00	444	0.02	0.71	466
Diesel engine, SH	0.87	11.85	0.06	675	0.11	0.08	711
Hay/Straw/Misc. gasification, SH	0.00	0.59	0.01	108	0.00	0.00	108
Wood gasification, SH	0.00	0.51	0.01	99	0.00	0.00	99
Fuel cells plant (hydrogen), SH, 2015	0.00	1.54	0.00	377	0.00	0.56	388
Fuel cells plant (nat. gas), SH, 2015	0.00	1.64	0.00	400	0.02	0.60	419
Fuel cells (hydrogen), SH	0.00	2.03	0.00	495	0.00	0.74	511
Fuel cells (nat. gas), SH	0.00	2.07	0.00	505	0.03	0.76	529

Source: Markal database.

Note: HT: high temperature heat for industry,
LT: low temperature heat for industry;
SH: space heating

2.3.1. Gas fuelled technologies

2.3.1.1 Gas turbine HT

We consider a 4MW turbine with a heat to power ratio (H/P) of 2.2. The high temperature process steam (e.g. 60 bar/500°C) is generated by the means of a waste heat boiler with the possibility of additional firing. Electrical efficiency is relatively low, at 25.5% in 2010. The investment cost is 45,000 BEF/kW_e, for a lifetime of 15 years.

Taking account of the production of heat as explained above, the production costs are 2.05 BEF/kWh_e, of which 1.41 francs are for the fuel.

The turbine is equipped with low NO_x burners. External costs are 0.46 BEF/kWh_e.

2.3.1.2 Back pressure turbine LT

This system (20 MW_e) consists of a conventional steam boiler with a back pressure turbine. This type of turbine has a low electrical efficiency (22%) balanced by a high H/P ratio of 3. Investment costs are high, at 52,000 BEF/kW_e for a lifetime of 25 years. Production costs amount to 2.76 BEF/kWh_e, of which fuel accounts for 1.79 francs.

It is equipped with low NO_x burners. External costs are 0.42 BEF/kWh_e.

2.3.1.3 Gas engines (SH and LT)

Gas engines are available in a wide range of capacity. We have selected here two sizes, one of 650 kW_e for uses in the residential and commercial sectors for space heating, and one of 1 MW_e, for low temperature heat production in industries. Efficiency is 34.5% (resp. 36% for the larger engines). They have a lifetime of 15 years. Investment cost is 26,000 BEF/kW_e (resp. 22,000 BEF/kW_e).

Production costs are 2.00 BEF/kWh (resp. 2.15 BEF/kWh), of which fuel accounts for the largest share: 1.18 BEF/kWh_e (resp. 1.23 BEF/kWh_e). External costs are low, at 0.13 BEF/kWh_e (resp. 0.06 BEF/kWh_e). No specific abatement device is included in these estimates.

2.3.1.4 STAG with cogeneration for industry (HT) and for residential /services (SH)

We consider a 30 MW_e STAG turbine with high temperature heat for industry (HT), and a 30 MW_e STAG turbine with lower temperature for district heating (SH), using natural gas. These two turbines are very similar, with investment costs at 34,000 BEF/kW_e, and a lifetime of 20 years. Operation and maintenance are slightly higher for the STAG providing heat for space heating. Efficiency is at 39% (and H/P=1) for the STAG providing high temperature steam, and at 45.5% (and H/P = 1.32) for the STAG for district heating. We considered that the STAG providing high temperature heat would operate 80% of the time (7000 hours per year), while the STAG providing heat for space heating would operate 50% of the time (4380 hours per year).

Production cost is slightly higher for the district heating STAG, at 1.68 BEF/kWh_e (of which 0.93 is for fuel), than for the HT heat STAG, at 1.48 BEF/kWh_e (of which 1.04 is for fuel).

These STAGs are equipped with a low NO_x burner. External costs are 0.41 BEF/kWh_e (high temperature heat) and 0.19 BEF/kWh_e (district heating).

2.3.2. Diesel engines (for SH)

We consider here slow diesel engines with a power of 1 MW_e and a speed of 750 rpm. Other types of diesel engines could be considered, but would have very similar characteristics in terms of cost and other variables used in this analysis. The heat produced by diesel engines is for space heating.

The investment cost for the engines is about 20,000 BEF/kW_e, and their lifetime is 20 years. By 2010, total production costs should be at 2.42 BEF/kWh_e. As these engines are not fitted with emission abatement, the external cost is high, at 2.94 BEF/kWh_e.

We expect efficiency to be at 39.5% in 2010. The heat to power ratio is 1.15.

2.3.3. Biomass

2.3.3.1 Hay/straw/miscanthus gasification and gas engine

2.3.3.2 Wood gasification and gas engine

We considered two biomass gasification units, one for wood, one for straw/hay/miscanthus, coupled with a gas engine [1]. A typical installation will have a capacity of 200 kW_e and a H/P ratio of 1.8. The heat produced is for space heating.

The wood gasification/gas engine unit is available starting in 2000, for an investment cost of 76,000 BEF/kW_e. Efficiency is 25.5% and lifetime 15 years. The production cost of electricity is 5.75 BEF/kWh_e and the external cost becomes negative because this technology is cleaner than the reference heat generation unit considered (a condensing boiler). Total cost including external costs is thus lower, at 5.44 BEF/kWh_e.

The hay/straw/miscanthus gasification/gas engine unit is available starting in 2005, for an investment cost of 84,000 BEF/kW_e. Efficiency is 22% and lifetime 15 years. Total production costs are 11.92 BEF/kWh_e and heat production, as in the case of wood, brings about an external benefit of 0.29 BEF/kWh_e. Total cost including external costs is thus lower, at 11.63 BEF/kWh_e. To compute emissions, we assumed that only miscanthus (the most efficient biomass energy vector among these three) was used, excluding other biomass fuels (hay, straw).

For CO_2 emissions, only the emissions caused by the biomass production have been taken into account. For other pollutants, after discussion with engineers in the project TTCR GAZEL at UCL, we assumed the values of a gas engine fuelled with natural gas. This clearly constitutes an upper limit. NO_x emissions could be reduced to 50% of that level. As the energy content of biomass gas is lower, the combustion temperature is also lower, and less NO_x is produced.

The huge cost difference between biomass from wood or miscanthus comes from the cost of growing miscanthus. This includes the full cost of production, i.e. we assume that the farmers have no available production capacity to work with on the set-aside land where the biomass crops are grown. All costs incurred for the production of biomass are thus attributed to the production of the crop.

2.3.4. Fuel cells

Several fuel cell technologies might emerge in the future. However, according to our sources [6], cost figures of the possible technologies (molten carbonate, phosphoric acid or solid oxide fuel cells) are very similar. Investment costs are expected to stabilise at around 1500 Euro/kW_e, once the technology will have matured. Lifetime should reach around 40,000 hours. Operation and maintenance costs should be in the 0.5-0.15 Euro/kWh_e range.

We did not consider the polymer exchange membrane fuel cells (PEMFC) in this report. From the data we received, PEMFC's would be anyway more expensive (on a per kWh basis) than other types of fuel cells, because of their much shorter expected lifetime (5,000 hours). They would thus be reserved for specific applications, where their technical advantages (such as a short start up time) would compensate their higher costs. The automobile market is a good example of possible applications for PEMFC's.

Fuel cells can be fuelled directly by hydrogen, or include a reformer that extracts hydrogen from a fuel, for example natural gas. The specific data used in our database are presented in the Table 8. We assumed a usage rate of 50% for fuel cells producing heat for residential/services, and 80% for fuel cells producing HT heat.

In some cases, we had no information on the NO_x emission factors of the reforming process. We then assumed that, from a life-cycle point of view, emission factors of fuel cells using hydrogen would be the same as those using natural gas.

Table I 8: Fuel cells data (2010/2015

	Start year	Lifetime	Usage rate (%)	Electric efficiency (%)	Invest cost (BEF/kW_e)
Fuel cells, hydrogen, HT	2015	10	80	53	58,500
Fuel cells, hydrogen, SH	2000	10	50	51	65,800
Fuel cells, large units, hydrogen, SH	2015	15	50	53.6	58,700
Fuel cells, natural gas, HT	2015	10	80	50	59,800
Fuel cells, natural gas, SH	2000	10	50	40	67,300
Fuel cells, natural gas, large units, SH	2015	15	50	50.5	58,700

2.4. References

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[5] Markal database, prepared by VITO and KULeuven

[6] Communication from Mr. Geeraert, based on *Economische gegevens voor fuel cells*, TI-KVIV, 25 nov 1998, Elie Stubbe, TEE, page 16

[7] Commission Ampere, rapports préliminaires, mars 2000

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2.5. Appendix: abbreviations

ASC:	advanced supercritical
BEF:	Belgian franc
CH_4:	methane
CHP:	combined heat and power (equivalent to CPD)
CO:	carbon monoxide
CO_2:	carbon dioxide
CPD:	combined production (equivalent to CHP)
GCC:	gas combined cycle
GDP:	gross domestic product
GHG:	green house gases
GJ:	giga joule
IDC:	interest during construction
HT:	high temperature steam for industry
IGCC:	integrated gasification combined cycle
kW:	kilowatt
kWh:	kilowatt-hour
LDO:	light distillate oil
LT:	low temperature steam for industry
MCFC:	molten carbonate fuel cells
MHTGR:	modular high temperature gas-cooled reactor
N_2O:	nitrous oxide

NO_x:	oxides of nitrogen
PAFC:	phosphoric acid fuel cells
PEMFC:	polymer exchange membrane fuel cells
PJ:	peta Joule
PM_{10}:	particulate matter (10µ diameters)
PWR:	pressurised water reactor
rpm:	round per minute
SC:	supercritical
SH:	space heating (low temperature heat for residential and services)
SO_x:	sulphur oxides
SOFC:	solid oxide fuel cells
STAG:	steam and gas turbine
USC:	ultra super critical
VOC:	volatile organic compounds