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pour
l'avenir

Analysis of the national potential for the application of high efficiency cogeneration

In accordance with Article 6 of Directive 2004/8/EC of the European Union

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Ministère
de l'Écologie,
de l'Énergie,
du Développement
durable
et de la Mer

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INTRODUCTION

Europe and France are committed to the 3 x 20 targets (20 % reduction of greenhouse gases (GGEs), 20 % renewable energies (REs) and a 20 % reduction of energy consumption) by 2020.

Cogeneration technology (the simultaneous production of heat and electricity) enables greater energy efficiencies to be achieved overall than those from technologies which produce heat and electricity separately, and is one of the solutions to be implemented to achieve these energy saving targets.

Consequently, the policy of supporting the development of cogeneration forms part of French energy policy since it may be linked with the two other targets in this area, which are the reduction of CO_2 emissions (through cogeneration electricity production replacing more carbon-intensive electricity production), and the increase in the share of REs in the French energy mix (through the mobilisation of biomass as fuel). The French context of an electricity production system which is on average low carbon, together with a biomass sector still in the process of being structured, is an element to take into account in the policy for the support of cogeneration.

During the 1990s and 2000s, gas cogeneration expanded rapidly in France under the influence of a policy of support via regulated tariffs for the feeding-in of electricity which provided heat consumers with sufficient economic visibility to trigger investment in cogeneration facilities. Since the late 2000s, this policy of support for cogeneration has been reoriented towards biomass cogeneration through successive calls for tender by the ERC (Energy Regulatory Commission), and by the implementation from 2002 of a tariff for the obligation to purchase electricity produced from biomass which encourages cogeneration; a tariff which was re-evaluated at the end of 2009.

While heating requirements are decreasing in many sectors of activity as a result of energy saving policies and the major obligation to purchase contracts for cogeneration are due to expire in the coming years, the cogeneration sector in France is now at a turning point in its development.

The aim of this study is to analyse the national potential for high efficiency cogeneration; in other words, to estimate both the technical potential (maximum capacity for cogeneration to fulfil heat requirements) and the economic potential, i.e. the development of the cogeneration sector by 2020 due to the effect, firstly of economic conditions, and secondly of currently known energy policies (support tariffs, regulatory arrangements).

This study falls within the scope of the transposition into French law of Cogeneration Directive 2004-08-EC and should help French authorities fulfil the requirements set by Article 6 of this directive.

I. METHODOLOGY AND PRINCIPAL HYPOTHESES

1. Methodology adopted

The first aim of the study is to estimate the theoretical maximum potential for cogeneration, i.e. the maximum capacity for cogeneration which it would be technically possible to install to meet heat demand. For this, quantification of heat requirements for the different activity sectors selected (cf. 'Targeted activity sectors', below) was first carried out.

Cogeneration does not generally meet 100% of heat requirements in these sectors. The analysis of the thermal load duration curves of each sector enables the identification of the share represented by cogeneration in the total requirement. This represents a certain capacity of installed cogeneration: this is the technical potential for cogeneration.

The economic constraints, excluded until this point, were then taken into account so that the development of the cogeneration installations could be determined. Different test cases of cogeneration were modelled in a given economic context, in order to study the economic profitability both of the units already installed and those coming to the end of the obligation to purchase contract, and of new installations. This approach has enabled the estimation of the economic potential of cogeneration.

In parallel, a number of interviews have been conducted with various stakeholders in the sector in order to validate the hypotheses in terms of technical and economic potential.

Lastly, following the conclusions from the previous stage it was possible to list a number of brakes on and levers for the development of cogeneration.

2. Targeted activity sectors

Given the particularities of the different activity sectors, particularly concerning their heat requirements, the study sought to separate them to examine them separately.

Firstly, heating networks, the majority of which serve residential buildings, but which also supply tertiary buildings and industry, were separated out. The activity sectors studied therefore also exclude the heating network share related to these sectors.

Regarding industry, only those industries having heat requirements of less than 200°C have been included in the study. In fact, given the technological peculiarities of cogeneration, heat requirements of more than 200°C cannot be satisfied by this technology. The industrial sectors which are divided off at this point are sectors which have considerable heat requirements.

Finally, greenhouses representing a sector in which cogeneration could play an important role, it has been decided to study this sector separately.

It has therefore been decided, in agreement with the professions concerned and the MEEDDM (French Ministry for Ecology, Energy, Sustainable Development and the Sea), to study the following sectors and sub-sectors:

Residential (exc. HN)
Collective
Individual
Tertiary (exc. HN)
Health
Education-Research
Co-housing
Sport-leisure
Shops
Cafés, hotels, restaurants
Offices
Transport (stations, airports)
Heating Networks
Industry (exc. HN)
Agri-food (inc. sugar refineries)
Chemicals (inc. elastomers)
Paper/cardboard
Refineries
Automobile equipment manufacturers
Other (aeronautical, electronics, etc.)
Other (exc. HN)
of which greenhouses

Table 1 – Activity sectors studied in the current study

Convention concerning the units of power and energy:

By convention, power in kW (or its multiples) stated in this report is electrical power. To avoid confusion between electrical power and thermal power, particularly within the same tables, the clarifications "kWe" and "kWth" are employed[1].

[1] The same concepts of "kWh e" and "kWh th" are used to designate the production of electrical and thermal energy respectively.

II. TECHNICAL POTENTIAL

The technical potential for cogeneration by 2020 is an estimation of the capacity for cogeneration which it is necessary to install to fully meet heat requirements by cogeneration. In other words, this is an evaluation of the total capacity for cogeneration which would be installed if this technology was used to meet a heat requirement each time this is technically possible, ignoring economic restraints.

For this purpose, an estimation of heat requirements in 2020 in the studied sectors was first carried out. By taking as a basis the technical characteristics of cogeneration, this has enabled the calculation of a total capacity which should be installed to fully meet this requirement, using different cogeneration technologies: this total installed power represents the technical potential of cogeneration.

1. Estimation of thermal requirements in 2008 and by 2020

Heat requirements have first been estimated for the year 2008. By taking as a basis in particular the heating PPI for 2009 [11], hypotheses on the development of heat requirements by 2020 have been defined to calculate heat requirements at that date.

a) Hypotheses concerning thermal requirements in 2008

Concerning the residential and tertiary sectors, the thermal requirements have been estimated from energy consumptions for heating and domestic hot water production (DHW). These consumptions result from the ADEME (French Environment and Energy Management Agency) study Les chiffres clés du bâtiment (Building sector key figures) [7].

Heat requirements in these sectors have thus been estimated by dividing this consumption by average yields. The calculation of average yields for heating and DHW production systems was in addition based on a study by VNK [9].

The enquête nationale de branche sur les réseaux de chaleur et de froid (National industry enquiry on heating and cooling networks) by the SNCU (French District Heating and Cooling Association) [8] has enabled an understanding of the networks' heat requirements.

Finally, the thermal requirements of industrial sectors are a result of the overlapping of various sources and interviews with trades unions.

These different sources and hypotheses are described in Annex 1 of the current report.

b) Hypotheses concerning the estimation of thermal requirements in 2020

The rates of development of heat requirements by 2020 have been based for most sectors on the hypotheses adopted in the 2009 heat PPI [11]. Only the hypotheses of growth in heat requirements by industry as considered in the PPI have been modified. These appear too optimistic to the sector stakeholders encountered during the current study and a hypothesis of stabilisation in heat requirements between 2008 and 2020 therefore appears more realistic. It is therefore this hypothesis which has been adopted.

The hypotheses are reviewed in detail in Annex 2 of this report.

c) Results

These hypotheses enable the evaluation of heat requirements for the different sectors for the years 2008, 2010, 2015 and 2020.

The table below describes the results obtained by sector at these different dates:

	Annual requirement TWh				
	2008	2010	2015	2020	Var. 2003-2020
Residential (exc. heating networks)	280.2	284.1	263.8	203.0	-28%
Collective	75.4	75.5	68.2	45.9	-39%
Individual	204.8	208.5	195.7	157.1	-23%
Tertiary (exc. heating networks)	75.6	77.7	66.8	34.1	-55%
Health	8.6	8.9	7.6	3.9	-55%
Education-Research	12.2	12.5	10.8	5.5	-55%
Co-housing	4.6	4.7	4.1	2.1	-55%
Sport-leisure	6.2	6.4	5.5	2.8	-55%
Shops	15.0	15.4	13.3	6.8	-55%
Cafés, hotels, restaurants	6.6	6.8	5.8	3.0	-55%
Offices	19.7	20.3	17.4	8.9	-55%
Transport (stations, airports)	2.6	2.7	2.3	1.2	-55%
Heating networks	25.2	26.8	28.0	31.4	25%
Residential	14.6	16.3	18.1	23.3	60%
Tertiary	9.0	8.8	8.2	6.5	-28%
Industrial	1.5	1.5	1.5	1.5	0%
Other	0.2	0.2	0.2	0.2	0%
Industry (exc. heating networks)	111.8	111.8	111.8	11L8	0%
Agri-foodstuffs (inc. sugar refineries)	13.7	13.7	13.7	13.7	0%
Chemical (inc. elastomers)	30.2	30.2	30.2	30.2	0%
Paper/cardboard	11.7	11.7	11.7	11.7	0%
Refineries	14.3	14.3	14.3	14.3	0%
Automobile equipment manufacturers	4.3	4.3	4.3	4.3	0%
Other (aeronautical, electronic, etc.)	37.6	37.6	37.6	37.6	0%
Other (exc. heating networks)	17.1	17.1	17.1	17.1	0%
of which greenhouses	16.4	16.4	16.4	16.4	0%
TOTAL	510	518	488	397	-22%

Table 2 – Estimation of the development of heat requirements in the different sectors adopted by 2020

2. The cogeneration sector in 2008

The data concerning total cogeneration output results from the annual survey of electricity production by the SOeS (French Observation and Statistics Office) [13]. The total installed electrical output from cogeneration in France in 2008 is therefore 6 336MWe, or 15 052MWth.

In order to obtain a more detailed description of the output than that available in the SOeS survey, distributions by sector, technology and power have been obtained from different detailed sources, and in particular from the 2005 CEREN (French Centre for Economic Studies and Research in Energy) study for the DGEMP (General Directorate for Energy and Raw Materials) [14].

Nevertheless, the present study is not intended to accurately update the previously mentioned sources. It is therefore based on existing sources and is concentrated on the estimation of the potential for cogeneration in 2020.

a) Distribution of the installed output by sector

To obtain the distribution of the 6 336MWe of installed cogeneration in 2008, the study was based on data from the ATEE (French Energy Environment Technical Association) concerning the installed output functioning on gas both under the obligation to purchase (OP), and excluding the obligation to purchase, cross-checked with the CEREN study [14].

As is shown in Figure 1, industry concentrates more than 60% of the total installed cogeneration output, compared to 12% for residential and tertiary:

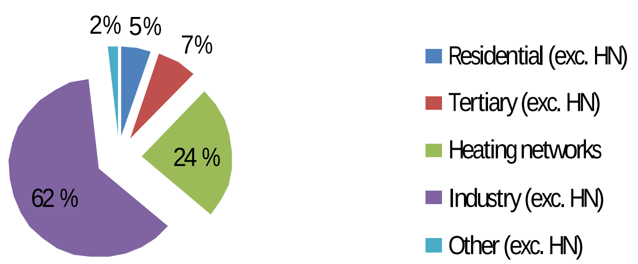

Figure 1 – Distribution by sector of the total installed electrical cogeneration output in 2008 (sources: SOeS [13], SNCU [8], CEREN [14], ATEE)

The detailed distribution by sector of the installed cogeneration output in 2008 is given in Table 3 below:

	Number of units		Total electrical output (MWe)					Recoverable thermal output (MWth)		Electricity production (GWh e)		Heat production (GWh th)	
			Natural gas		Other comb.	Total							
			under OP	excl. OP									
Residential (exc. heating networks)	161	13%	329	0	0	329	5%	389	3%	981	5%	1 380	3%
Collective	161	13%	329	0	0	329	5%	389	3%	981	5%	1 380	3%
Individual	0	0%	0	0	0	0	0%	0	0%	0	0%	0	0%
Tertiary (exc. heating networks)	243	20%	392	57	0	449	7%	487	3%	1 303	6%	1 692	3%
Health	156	13%	217	35	0	252	4%	319	2%	732	3%	1 108	2%
Education-Research	35	3%	64	2	0	66	1%	95	1%	191	1%	331	1%
Co-housing	0	0%	0	0	0	0	0%	0	0%	0	0%	0	0%
Sport-leisure	20	2%	53	0	0	53	1%	22	0%	154	1%	76	0%
Shops	4	0%	3	3	0	6	0%	7	0%	16	0%	24	0%
Cafés, hotels, restaurants	0	0%	0	0	0	0	0%	0	0%	0	0%	0	0%
Offices	21	2%	12	3	0	15	0%	19	0%	43	0%	65	0%
Transport (stations, airports)	7	1%	43	14	0	57	1%	25	0%	166	1%	88	0%
Heating networks	234	20%	1 376	62	76	1 513	24%	2 284	15%	5 791	27%	7 704	15%
Industry (exc. heating networks)	509	43%	2 343	429	1 159	3 930	62%	11 750	78%	13 245	61%	39 202	78%
Agro-foodstuffs (inc. sugar refineries)	171	14%	226	96	297	619	10%	2 769	18%	1 957	9%	8 660	17%
Chemical (inc. elastomers)	118	10%	1 066	42	231	1 339	21%	3 142	21%	4 233	20%	9 826	19%
Paper/cardboard	91	8%	678	14	180	872	14%	2 245	15%	2 757	13%	7 019	14%
Refineries	38	3%	45	250	276	571	9%	1 945	13%	2 627	12%	8 541	17%
Automobile equipment manufacturers	42	3%	238	17	125	379	6%	1 183	8%	1 199	6%	3 699	7%
Other (aeronautical, electronic, etc.)	50	4%	90	10	49	150	2%	466	3%	473	2%	1 458	3%
Other (exc. heating networks)	48	4%	104	0	10	114	2%	142	1%	324	1%	542	1%
of which greenhouses	47	4%	102	0	10	112	2%	140	1%	349	2%	534	1%
TOTAL	1 195	100%	4 543	547	1 245	6 336	100%	15 052	100%	21 645	100%	50 520	100%

Table 3 – Distribution by sector of the installed cogeneration output in 2008 (sources: SOeS [13], SNCU [8], CEREN [14], ATEE)

b) Distribution of the installed output by technology

The gas turbine is currently the dominant technology in terms of the installed electrical power. It represents more than half of the cogeneration output:

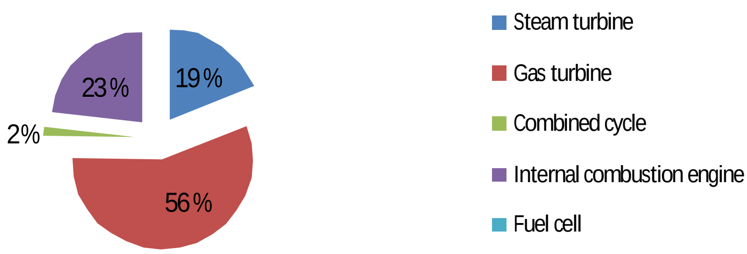

Figure 2 – Distribution by technology of the total installed electrical cogeneration output in 2008
(sources: SOeS [13], CEREN [14])

The detailed distribution by technology of the installed cogeneration output in 2008 is given in Table 6 below:

Table 4 gives the distribution of the different technologies by electrical output[2]:

	Steam turbine	Internal combustion engine	Gas turbine	Micro-turbines
36 kWe < P • 1 MWe	1%	6%	0%	100%
1 < P • 2 MWe	2%	53%	1%	0%
2 < P • 5 MWe	14%	39%	5%	0%
5 < P • 10 MWe	26%	2%	14%	0%
10 < P • 20 MWe	41%	1%	9%	0%
20 < P • 50 MWe	14%	0%	49%	0%
P > 50 MWe	2%	0%	22%	0%
TOTAL	100%	100%	100%	100%

Table 4 – Distribution of cogeneration technologies by power range for the installed output
(sources: CEREN [14], interviews)

[2] Micro-cogeneration, with a power of less than 36 kWe, remains for the present rather marginal in France and is not taken into account in this chapter due to a lack of accurate data. Nevertheless, some key figures can be mentioned which result from studies by Gaz de France and the petitecogeneration.org site: France currently has around 70 micro-cogeneration plants, with a total electrical power of around 670 kWe and a thermal power of around 1 780 kWth.

c) By electrical output

Large power cogeneration plants (more than 10 MWe) represent the biggest share of the total installed electrical power. These are essentially gas turbines installed in the industrial sector.

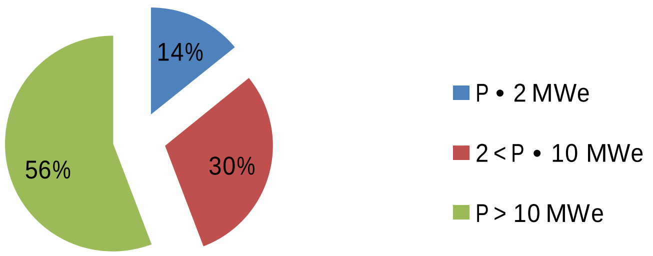

Figure 3 – Distribution by power range of the total installed electrical cogeneration output in 2008 (sources: SOeS [13], CEREN [14])

The detailed distribution by electrical power of the installed cogeneration output in 2008 is given in Table 7 below:

Table 5 gives the distribution of the electrical power ranges by technology:

	Steam turbine	Internal combustion engine	Gas turbine	Micro-turbines	TOTAL
36 kWe < P • 1 MWe	11%	80%	5%	4%	100%
1 < P • 2 MWe	5%	93%	2%	0%	100%
2 < P • 5 MWe	26%	57%	17%	0%	100%
5 < P • 10 MWe	52%	3%	45%	0%	100%
10 < P • 20 MWe	73%	1%	27%	0%	100%
20 < P • 50 MWe	14%	0%	86%	0%	100%
P > 50 MWe	6%	0%	94%	0%	100%

Table 5 – Distribution of power ranges by technology for the installed output (sources: CEREN [14], interviews)

	Number of units		Total electrical power (MWe)		Recoverable thermal power (MWth)		Electricity production (GWh e)		Heat production (GWh th)	
Steam turbine	141	12%	1 200	19%	6 951	46%	4 120	19%	21 935	43%
Gas turbine	210	18%	3 562	56%	6 227	41%	13 089	60%	23 111	46%
Combined cycle	4	0%	105	2%	174	1%	386	2%	644	1%
Internal combustion engine	839	70%	1 469	23%	1 700	11%	4 049	19%	4 829	10%
Fuel cell	1	0%	0.2	0%	0.2	0%	1	0%	1	0%
TOTAL	1 195	100%	6 336	100%	15 052	100%	21 645	100%	50 520	100%

Table 6 – Distribution by technology of the installed cogeneration output in 2008 (sources: SOeS [13], CEREN [14])

	Number of units		Total electrical power (MWe)		Recoverable thermal power (MWth)		Electricity production (GWh e)		Heat production (GWh th)	
36 kWe < P • 1 MWe	148	12%	103	2%	149	1%	264	1%	409	1%
1 < P • 2 MWe	518	43%	798	13%	991	7%	2 257	10%	2 826	6%
2 < P • 5 MWe	287	24%	964	15%	2 579	17%	2 901	13%	7 385	15%
5 < P • 10 MWe	122	10%	935	15%	3 110	21%	2 993	14%	10 053	20%
10 < P • 20 MWe	67	6%	1 017	16%	4 383	29%	3 521	16%	14 534	29%
20 < P • 50 MWe	44	4%	1 784	28%	3 013	20%	6 987	32%	11 847	23%
P > 50 MWe	9	1%	734	12%	828	6%	2 723	13%	3 465	7%
TOTAL	1 195	100%	6 336	100%	15 052	100%	21 645	100%	50 520	100%

Table 7 – Distribution by power range of the installed cogeneration output in 2008 (sources: SOeS [13], CEREN [14])

3. Estimation of the technical potential of cogeneration by 2020

a) General methodology

The technical potential represents the maximum cogeneration power that it would be technically possible to install to meet the total heat requirements (cf. part 1: 'Estimation of thermal requirements in 2008 and by 2020'): Taking into account its base load dimensioning for heating, cogeneration does not generally correspond to 100% of heat requirements, for example in the case of low requirements (at the start and end of the heating season), and peaks in demand.

In order to determine the share of the requirement which cogeneration can cover, different heat withdrawal profiles (hourly, daily and monthly) have been created for each of the sectors and sub-sectors studied. These profiles enable the determination of the load duration curves for heat consumption by the sector concerned; in other words, the classification of the hourly heat consumption (expressed as a share of the total requirement) by descending order over the year.

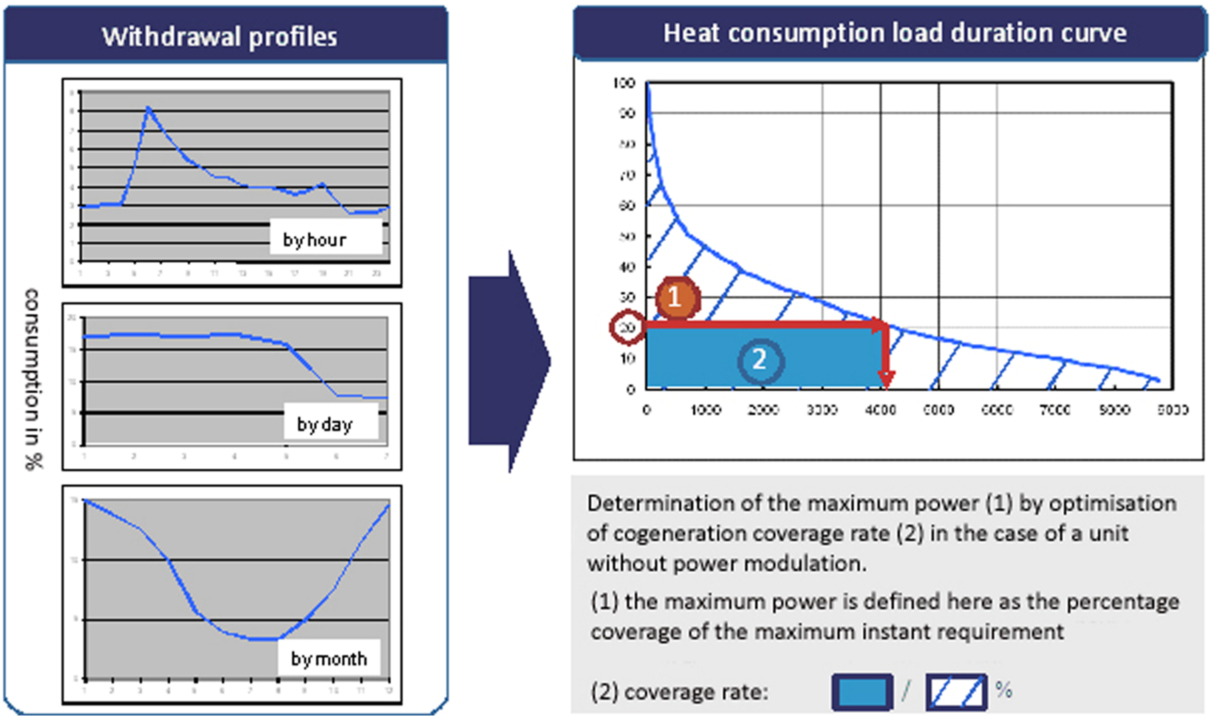

Figure 4 – Methodology of cogeneration dimensioning (example relating to offices)

Once the estimation of the share of the requirements which can potentially be covered by cogeneration has been carried out, the technical potential is determined for each sector and sub-sector, according to the following methodology:

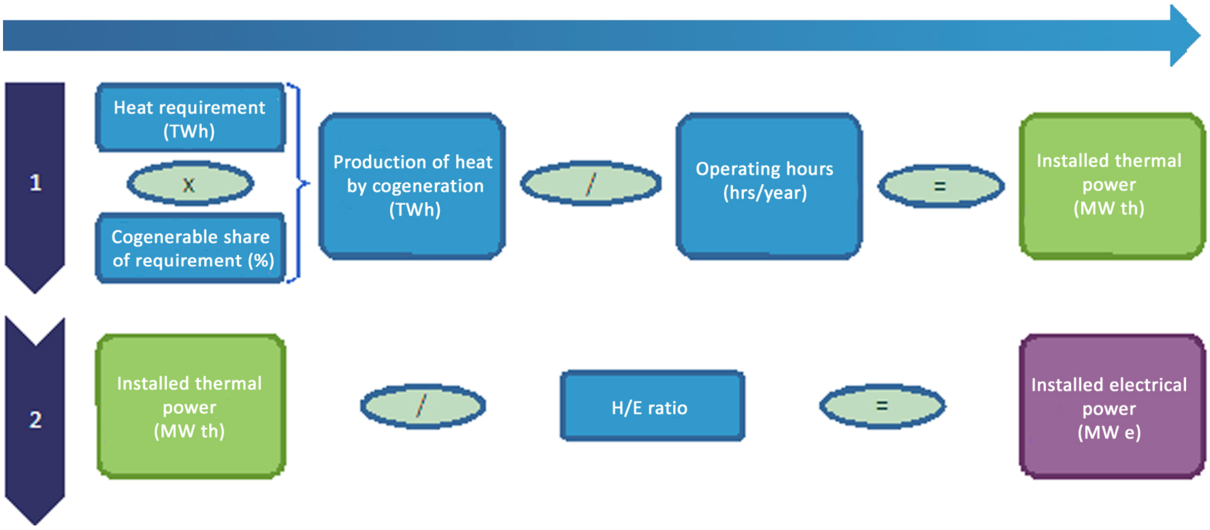

Figure 5 – Methodology followed to determine the technical potential of each sector in terms of installed thermal and electrical power

b) Hypotheses

The hypotheses employed in establishing the technical potential of cogeneration are described in Annex 4.

The load duration curves selected in this way enable the establishment of an average heat requirement which can be covered by cogeneration of 54%. On average, cogeneration has been considered as functioning 3 335 hours per year, with an average H/E ratio of 2.11 for all technologies together.

c) Results

i. Technical potential by sector

Applying the methodology described in Figure 5 to each of these sectors, the installed cogeneration capacity for each sector was calculated from the estimation of heat requirements for 2020 (cf. '1. Estimation of thermal requirements in 2008 and by 2020').

A maximum of 54% of heat requirements can theoretically be covered by cogeneration in 2020. The maximum corresponding cogeneration capacity - the technical potential - is around 64 GWth, corresponding to around 30 GWe.

Table 8 below describes the share of the requirement which can be covered in each of the studied segments, and the associated technical cogeneration potential:

	Annual heat requirement		Cogeneration output			Annual heat requirement		Cogeneration output			
	2008		2008			2020		2020			
	TWh		TWh th	% heat req't	MWe	TWh		TWh th	% heat req't	MWe	MWth
Residential (exc. heating networks)	280	55%	1	0%	329	203	51%	87	43%	12 190	25 935
Collective	75	15%	1	2%	329	46	12%	20	43%	6 135	5 865
Individual	205	40%	0	0%	0	157	40%	68	43%	6 055	20 070
Tertiary (exc. heating networks)	76	15%	2	2%	449	34	9%	14	42%	3 705	4 110
Health	9	2%	1	13%	252	4	1%	2	45%	475	500
Education-Research	12	2%	0	3%	66	6	1%	2	39%	585	620
Co-housing	5	1%	0	0%	0	2	1%	1	43%	315	260
Sport-leisure	6	1%	0	1%	53	3	1%	1	47%	365	385
Shops	15	3%	0	0%	6	7	2%	3	41%	680	805
Cafés, hotels, restaurants	7	1%	0	0%	0	3	1%	1	45%	320	385
Offices	20	4%	0	0%	15	9	2%	3	39%	840	1 000
Transport (stations, airports)	3	1%	0	3%	57	1	0%	1	46%	125	155
Heating networks	25	5%	8	31%	1 513	31	8%	14	45%	2 920	4 195
Industry (exc. heating networks)	112	22%	39	35%	3 930	112	28%	89	80%	8 950	27 240
Agro-foodstuffs (inc. sugar	14	3%	9	63%	619	14	3%	10	70%	1 075	3 055
Chemical (inc. elastomers)	30	6%	10	33%	1 339	30	8%	23	75%	1 950	7 250
Paper/cardboard	12	2%	7	60%	872	12	3%	11	96%	970	3 600
Refineries	14	3%	9	60%	571	14	4%	14	96%	1 345	3 125
Automobile equipment	4	1%	4	86%	379	4	1%	3	71%	365	975
Other (aeronautical, electronic, etc.)	38	7%	1	4%	150	38	9%	29	77%	3 245	9 235
Other (exc. heating networks)	17	3%	1	3%	114	17	4%	10	57%	2 575	2 580
of which greenhouses	16	3%	1	3%	112	16	4%	10	60%	2 575	2 580
TOTAL	510	100%	51	100%	6 336	397	100%	215	54%	30 340	64 060

Table 8 – 2020 technical cogeneration potential by sector

ii. Technical potential by technology

To move from technical potential by sector to potential by technology, hypotheses concerning the distribution of each technology by sector have been made. These hypotheses, described in Annex 4 of this report, lead to the following distribution of technical potential for 2020:

	Cogeneration output				Cogeneration output			
	2008				2020			
	MWe		MWth		MWe		MWth	
Steam turbine	1 200	19%	6 951	46%	4 095	13%	22 110	35%
Gas turbine	3 562	56%	6 227	41%	3 930	13%	5 895	9%
Combined cycle	105	2%	174	1%	2 255	7%	2 255	4%
Internal combustion engine	1 469	23%	1 700	11%	12 280	40%	12 280	19%
Fuel cell	0	0%	0	0%	1 500	5%	750	1%
Micro-cogeneration	0	0%	0	0%	6 280	21%	20 770	32%
Micro-turbines	0	0%	0	0%	30	0%	50	0%
Internal combustion engines	0	0%	0	0%	625	2%	1 500	2%
Assimilated Stirling engines (external combustion engine)	0	0%	0	0%	4 375	14%	18 595	29%
Fuel cells	0	0%	0	0%	1 250	4%	625	1%
TOTAL	6 336	100%	15 052		30 340	100%	64 060	100%

Table 9 – 2020 technical potential by technology

We can observe a significant technical potential in terms of internal combustion engines, which represent 40% of the technical potential. Indeed, this technology has the advantage of adaptability in various situations to meet a given heat requirement.

Moreover, micro-cogeneration, and in particular Stirling engines, constitute a significant technical potential (essentially in the Residential sector < 36 KWe).

III. ECONOMIC POTENTIAL

The economic potential of cogeneration by 2020 is a projection of the development of the cogeneration output under the influence, firstly of economic parameters, and secondly of currently known energy policies (support tariffs, regulatory provisions).

The calculation of this potential is based on simulation of the decisions of heat consumers who may decide to opt for a cogeneration system or a classic heat production system.

It is clear that these decisions are dependent on several parameters and particular local situations: fuel supply conditions, actual installation yields, and operational and financial constraints of the heat consumer.

Nevertheless, and in order to perceive the overall trends in the development of the sector, we have chosen to carry out modelling of the choices for the main alternatives which are presented to the heat consumer (choice of technology, choice of fuel, and choice of electricity sales regime). These choices, carried out annually depending on the development of the parameters (exit from purchase regime, calls for tender by the ERC, etc.), result in the development of the installed cogeneration output.

In order to simplify this model, we have defined different categories of heat consumers from those used in the previous chapter (Technical potential), in order to intersect the broad lines of choice: industry vs. heating network vs. tertiary vs. individual, power currently installed less or greater than 12 MWe.

Finally, to produce a projection of stakeholders' choices, we have constructed a simplified micro-economic model enabling the comparison of the current net values of the different alternatives. Criteria other than economic (e.g.: policy in favour of REs, noise or location criteria, etc.) were also taken into account in projecting the choices of heat consumers.

1. Economic hypotheses

The development of cogeneration output, i.e. both the maintenance or abandonment of capacities currently installed and the installation of new units, depends to a large extent on the economic context of cogeneration: fuel cost, sale price of heat and electricity, operating costs of cogeneration units, etc. The following paragraphs describe the main hypotheses made in this context.

a) Cogeneration installation costs

The installation costs used in the economic model, in €/kWe, are the costs of the purchase and installation of the material, in particular the integration of the civil engineering necessary for the correct construction of installed systems, and the expenses for connection to the electricity network.

Even within one technology, these costs per installed kW vary significantly depending on the electrical power of the facility.

All costs used are described in Annex 6 of this report. We arrive at a figure for costs of around € 700/kW for a 40 MW gas turbine. This cogeneration technology is mature and well developed on the French market. Another mature technology, the steam turbine, has costs of around € 1 500/kW for 10 MW extraction turbines and € 4 000/kW for back-pressure turbines, when they are used for biomass cogeneration.

Installation costs for micro-cogeneration, a less mature technology which remains little developed in France, (cf. 'III.4 Focus on micro-cogeneration', page 54, for more details concerning micro-cogeneration), are currently around € 3 000 to € 10 000/kW for the 1 to 36 kW power range.

b) Cogeneration operating costs

The operating costs considered in this study, expressed in €/kWh e, exclude fuel costs, which are accounted elsewhere. They include, in particular, equipment maintenance visits, expenses for personnel dedicated to cogeneration, and insurance. All costs used are described in Annex 6 of this report.

These costs vary from one technology to another. From € 0.011/kWh e for a 40 MW gas turbine, they may vary from € 0.08/kWh e for a steam back-pressure turbine of a few MW to € 0.16/kWh e for a 0.5 MW back-pressure steam turbine operating on biomass.

Maintenance costs have been assumed to increase by 2% per year[3].

c) Cost of renovation and overhaul

At the end of an obligation to purchase contract, a cogeneration facility may, if it desires to continue to produce electricity, either benefit from the renovation tariff[4], or go onto the electricity market.

To be eligible for contract C01-R, a facility renovation with a minimum investment of € 350/kW installed[5] is required, this threshold being indexed annually. Following interviews carried out with the profession, it has been set for this study at € 380/kW. Cogeneration facilities coming to the end of the obligation to purchase contract must be reviewed in order to ensure maximal performance.

If the cogeneration facility is not eligible for contract C01-R and/or if it decides to go onto the market, major maintenance (or overhaul) is still necessary. This operation is essential every ten to fifteen years for the correct operation of the facility. Interviews carried out with the profession have enabled us to set this cost at € 150/kW.

[3] The same hypothesis as in the IGF-CGM (General Inspectorate of Finance-General Council of Mines) report [6]
[4] Only cogeneration facilities of less than 12 MWe are eligible for contract C01-R.
[5] Value for January 2007.

d) Prices of fuels

Simulations have been carried out on the basis of the following fuel costs:

€/MWh LHV	Fuel	Associated CO_2 cost* (€ 15/tCO_2)	TOTAL
Natural industry gas (STS)	27	3.5	30.5
Wood biomass	18	0	18

Table 10 – Hypotheses regarding 2010 prices of fuels (*including the price of CO_2 where applicable)

Energy costs have been assumed to increase by 2% per year in the basic scenario, whatever the energy type.

e) Price of heat

The price of heat was based on the fuel costs for a classic gas boiler (90% yield). This also includes, when the facilities are operating under quotas, the cost of CO_2.

Nevertheless, cogenerators have offered heat price reductions to their customers in exchange for certain inconveniences which cogeneration may represent (in particular commitment to a heat requirement over a long period). The scenarios being very different, we have made estimations of average values following the various interviews carried out. These reductions given by the cogenerators were considered in the study as being:

- 10% in industry
- 5% in heating networks

The heat price has thus been calculated in the following manner:

$$(\text{Price of gas STS} + \text{Price of } CO_2^{*})/90\% - \text{reduction}$$

Equation 1 – Calculation of heat price (*cost of CO_2 where applicable)

The development of heat prices is determined by that of gas and of CO_2. In the reference scenario, the price of CO_2 remains set at € 15/tonne (hypothesis recommended by the European Commission).

Special case of heating networks exceeding the threshold of 50% RE

In the special case of heating networks exceeding the threshold of 50% of RE and for which heat is then sold with a VAT rate of 5.5%, the economic attractiveness of solutions making it possible to adhere to this condition is increased. In order to model this interest, the operating costs were reduced by 10% for facilities allowing networks to adhere to this threshold.

This is, of course, only a means of taking into account the economic benefit provided by reduced VAT, and is not an economic reality.

f) Tariffs for the sale of electricity

In the economic model used in this study, the electricity produced by cogeneration is either purchased in the context of an obligation to purchase or sold directly on the electricity market.

In the basic scenario, the indexation of purchase prices and the increase in the price of electricity on the market have been assumed to equate to 2% per year.

i. Purchase tariffs

In the case of a technology operating on gas, the purchase tariff considered in this study is the C01-R tariff[6], granted during the renovation of gas facilities of less than 12MW power. This tariff is granted on the basis of a minimum investment during the renovation of the facility (cf. section 'c) Cost of renovation and overhaul').

To model the purchase of electricity cogenerated from biomass, we have assumed an average purchase level of € 150/MWh. This level corresponds to the tariff attained in the last biomass CFT (ERC 3)[7], and to the level of purchase for facilities from 5 to 12 MW[8].

ii. Electricity market

On the basis of the observation that the market prices for electricity are to a large extent determined by those of the gas market, we have chosen in this study to calculate the price of the electricity market on the basis of gas prices. The profitability level of CCGTs determines to a significant extent the levels of the price of the electricity market.

This profitability can be measured by the clean spark spread[9]: at "peak"[10] times on the electricity market, the average level observed from 2003 to 2009 (around € 20/MWh) ensures the profitability of CCGTs. The hypothesis has been made that these levels of clean spark spread and thus of CCGT profitability, should be maintained in the medium term.

To calculate the corresponding electricity price, the market taken as a reference for gas is the Zeebrugge spot gas market[11]. This market currently has a surplus, which leads to low prices (a "gas bubble"). The hypothesis has been made that the trend is an increase in prices in the medium term (end of the bubble). Analysts asked during the current study estimate that the fundamental balance of the market should lead to the disappearance of this imbalance in the medium term.

[6] Contract with a duration of 12 years.
[7] Average tariff € 145; this tariff is indexed (contract applicable over a period of 20 years)
[8] This indexed tariff is applicable over a period of 20 years; it constitutes the sum of a reference tariff and a complementary bonus.
[9] Price of electricity less the cost of the gas purchased to produce this quantity of electricity, less the cost of the associated CO_2
[10] Working days from 08:00 to 20:00
[11] Hourly price of gas exchanged between gas operators and gas purchase price for a CCGT

The price of the Zeebrugge hub has thus been fixed in this study at the STS price minus € 5 (average gap observed before the gas bubble).

g) Modelling

The financial analysis carried out for the different test cases is based on the hypotheses previously explained. The number of hours of operation of cogeneration and the associated boiler to fulfil the heat requirements of the site considered then enables the calculation of the products associated with the sale of electricity and heat, and the marginal cost of production.

For each of the cases, the net present value (NPV) and the internal rate of return (IRR) are calculated. These economic indicators then enable the comparison between the different cases.

Examples of results from the model are given in part 'c) Model results' of Annex 6 of the current report.

2. Cogeneration capacity development model

a) Methodology

In order to establish the development in cogeneration capacities, different key sectors have been identified. These sectors represent the main heat consumer sectors.

Three major sectors were first identified: industry, heating networks and residential-tertiary. The decision levers are in fact not the same for these sectors: while industry concentrates above all on economic criteria for the choice of technology used to meet heating requirements, heating networks may be more influenced by political considerations (positive image of biomass, for example).

Next, within these major activity sectors, a division by electrical cogeneration power was considered necessary to carry out a more detailed analysis. The 12 MW threshold represents, in various ways, (obligation to purchase contract for gas or biomass, biomass CFT, etc.) an access limit for certain pricing conditions. This distinction between installed power greater than 12 MW and less than 12 MW was therefore made only for the industrial and heating network sectors, the residential-tertiary sector not having a unit achieving such a size.

It should be remembered that while it is easier to think in terms of electrical power, the dimensioning of the facility is done in terms of heat requirements, which enables the determination of a corresponding thermal power. Depending on the cogeneration technology used, the heat/electricity ratios are different and the electrical power associated varies for a given thermal power. The facilities accounted in a category 'greater than 12 MWe' are facilities which initially have an electrical power of more than 12 MW. During an energy change, and taking into account the H/E ratios of different technologies, it is possible that the new facility has a power less than 12 MW. The electrical power of a corresponding site is accounted in the 'greater than 12 MWe' section for better legibility of the results.

In addition, given their specific needs in terms of heat and fuel used, paper mills, refineries and agri-foodstuffs industries have been separated. These are industries possessing an internal or controlled fuel resource and which are likely to want to use this resource through adapted cogeneration technologies. This sub-sector also includes greenhouses which have constant heat requirements that can be met in part by biogas resulting from the methanisation of ELs.

Finally, the residential-tertiary sector was separated into two sub-sectors: Collective residential and Tertiary > 36 kWe, where cogeneration may be used in boiler systems, and Residential < 36 kWe in which micro-cogeneration may develop.

The following seven sectors have thus been adopted:

Sectors modelled
Industry > 12 MWe (excluding specific sectors)
Industry < 12 MWe (excluding specific sectors)
Specific industrial sectors (paper mills, refineries, agri-foodstuffs)
Major heating networks > 12 MWe
Minor heating networks < 12 MWe
Collective residential and Tertiary > 36 kWe
Residential < 36 kWe

Table 11 – Key sectors adopted in the cogeneration capacity development model

For each of these sectors, different alternatives may be available to existing cogeneration facilities at the end of the obligation to purchase contract or which wish to change fuel. Depending on heat requirements and the profitability of the cogeneration facilities, new units may also be installed. This data results from the micro-economic model and the different interviews carried out with the profession.

This paragraph is intended to describe the main alternatives available depending on the sector and the associated progression rate.

b) Results by key sector

i. Industry > 12 MWe (excluding specific sectors)

Cogeneration facilities of more than 12 MWe installed in industry (excluding specific sectors), essentially gas turbines, are progressively going to leave the purchase tariff without the possibility of accessing a "renovation tariff". With the end of the obligation to purchase, these cogeneration facilities will have the choice in each of the following years of either being dismantled or going on the market. The implementation of a policy of support for biomass cogeneration should enable the development of a capacity of nearly 250 MW by 2020.

In the end, the total installed cogeneration power in this sector should quite clearly reduce (from around 280 MW) between 2010 and 2020, the increase in biomass being unable to compensate for the dismantling of certain gas capacities.

The development expected by the cogeneration output in this sector is thus as follows:

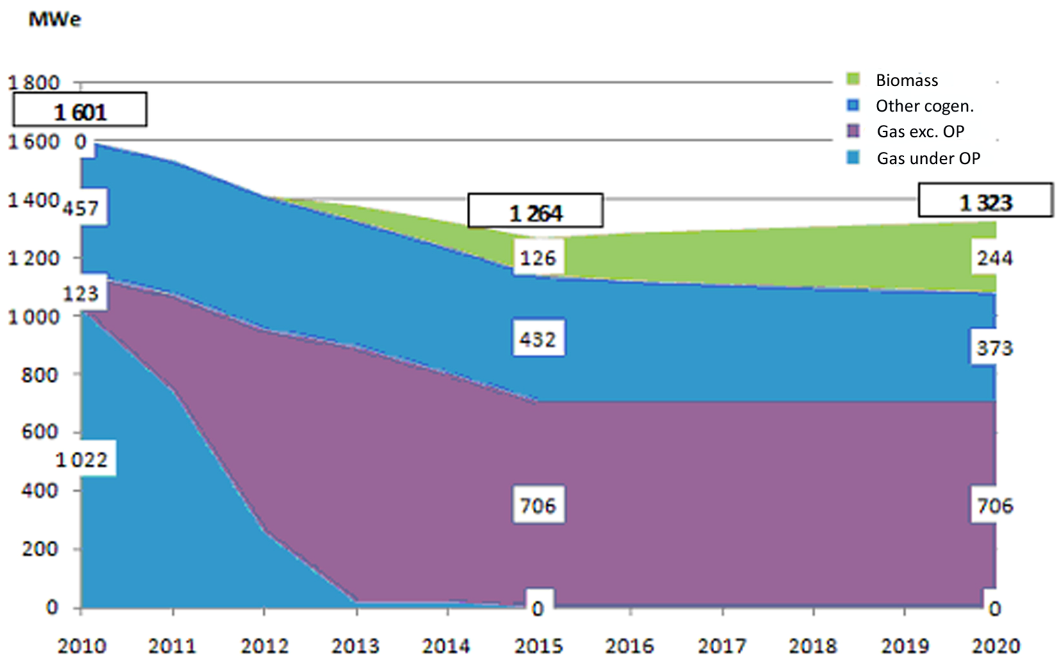

Figure 6 – Development in installed cogeneration capacities in the Industry sector > 12 MWe (excluding specific sectors)

To continue to meet heat requirements, industry is confronted with the following choices:

- Operate on the free electricity market while continuing to use gas cogeneration: This choice particularly concerns facilities whose flexibility is sufficient to enable a weekly or daily stoppage, thus leading the facility to operate when electricity prices are sufficiently high to cover operating costs. This operation is strongly dependent on the economic context of the energy market (clean spark spread), and the risk inherent in the energy market (a risk which industrial heat consumers control less than the power producers) may limit the decision to invest in overhaul[12] (major renovation which should be carried out every ten to fifteen years and necessary to the correct function of operations over the period 2010-2020). In the context of the economic hypotheses which we have adopted, we have estimated that this operation regime may be adopted by around 60% of cogenerators. In fact, according to our model, the choice of this option is second in terms of net present value, but requires less investment than the biomass cogeneration alternative. However, it nonetheless probably translates into a lower number of operating hours than before (around 2 000 hours on average) to the extent that the operation of cogeneration on the free market is only profitable on a limited number of days in the year.

- Convert the facility into a biomass cogeneration facility on the basis of purchasing tariffs and ERC CFTs: when moving to biomass cogeneration the H/E ratio is higher than for the gas technologies, so the installed electrical power is reduced and the heat consumer can probably choose between ERC CFTs and purchasing tariffs which are reserved for electrical powers between 5 and 12 MWe. This arrangement enables the heat consumer to have significant visibility over time (20 years). While the net present value modelled for this option is the best of the three alternatives on paper, the high level of investment, the necessity to control sources of biomass (and in particular the price of biomass), together with the certainty of the sustainability of heat requirements, remain major brakes on the development of large-scale biomass cogeneration facilities for those industrial sectors not naturally implicated in the wood sector. We estimate that around 20% of the facilities currently using cogeneration should choose this option.

- Dismantle the cogeneration facility and go back to a gas boiler: this solution has the benefit of representing a low investment, as a boiler is often already present on the site[13]. This solution also offers increased flexibility and ease of use. Nonetheless, it is the least good option in terms of net present value. In our estimation, around 20% of industrial actors in this sector currently possessing a cogeneration facility should choose this alternative.

These different alternatives have been integrated into the model with the following progression rates (from the current situation to a given alternative)[14]:

Alternative	Progression rate
Operate on the free market, continuing to use gas	60%
Conversion to biomass cogeneration	20%
Dismantle the cogeneration facility and go back to a gas boiler	20%

Table 12 – Progression rate between the different alternatives open to cogenerators in the Industry sector > 12 MWe (excluding specific sectors)

To these developments in the installed output can be added new biomass cogeneration facilities, with in particular the commissioning of ERC CFTs 2 and 3. The next call for tenders, which only concerns facilities of more than 12 MWe, will also enable the development of biomass cogeneration in this sector.

ii. Industry < 12 MWe (excluding specific sectors)

Taking advantage of the renovation tariff opportunity, the gas capacity currently installed in this sector should be able to remain almost constant. Within this gas cogeneration output, one part may opt for the free market, while other cogeneration facilities will disappear, particularly under the effect of the reduction in heat requirements.

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[12] Cf. 'Cost of renovation and overhaul', page 26

[13] This boiler may require renovation. However, the renovation costs are low compared to the sums incurred in the case of cogeneration. It should also be noted that cogeneration may be at least in part resold (in particular overseas).

[14] The progression rates for the different sectors are summarised in Annex 7.

The development expected by the cogeneration output in this sector is thus as follows:

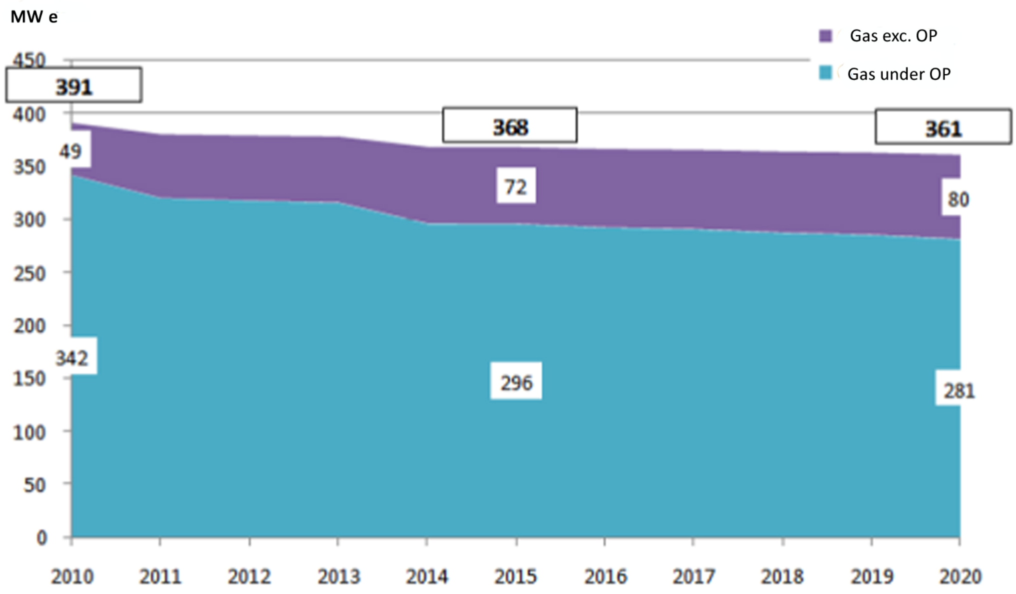

Figure 7 – Development in installed cogeneration capacities in the Industry sector < 12 MWe (excluding specific sectors)

Industrial actors are confronted with the following choices:

- Renovate the facility to benefit from the purchasing tariff: cogeneration facilities of less than 12 MWe installed in this sector, essentially gas turbines and gas engines, will be able to benefit from the renovation tariff on condition of a minimum investment (cf. 'Cost of renovation and overhaul', page 26) and by renewing their commitment for a twelve year period. This alternative appears in our model as being the most economically profitable (higher net present value) and should be chosen by a vast majority of industrial actors possessing an eligible gas cogeneration facility. However, certain factors are limiting, in particular: the necessity to have a sustainable heat requirement to be able to make cogeneration profitable, which represents a major investment whether outsourced or not (commitment to a twelve year period), the associated risk of the integration of CO_2 quota costs for facilities subject to the ETS, together with the constraints of connection to the network for the sale of electricity.

- Go on the electricity market: these facilities may also decide to take the opportunity to go on the market, in particular depending on their power. This option is a priori less attractive in terms of NPV but may constitute a "waiting" choice before the decision to invest in renovation, as access to the renovation tariff could be obtained later. In addition, this activity is far from the heart of the industrial actor's business, so it would not come without a significant access cost (particularly in terms of control of the electricity market).

- Dismantle the cogeneration facility and go back to a gas boiler: as in the 'Industry > 12 MW' case, the low investment associated with this alternative should enable a small number of industrial actors to relieve themselves of their cogeneration facility, particularly in the case of a significant reduction in heat requirements, even if the net present value of this option is lower.

The model is therefore founded on the following progression rates:

Alternative	Progression rate
Renovate the facility to benefit from the purchasing tariff	80%
Go on the electricity market	10%
Dismantle the cogeneration facility and go back to a gas boiler	10%

Table 13 – Progression rate between the different alternatives open to cogenerators in the Industry sector < 12 MWe (excluding specific sectors)

In addition, the thermal requirements of this segment are too low to enable the implementation of wood cogeneration facilities in the context of the ERC CFTs and the feed-in tariff

iii. Specific industrial sectors (paper mills, refineries, agri-food)

These industrial sectors generally have significant and relatively constant heat requirements This is precisely the situation in which cogeneration is of most interest. Contrary to the industrial sectors considered above, the total cogeneration capacity should be stable or even slightly increase in the specific industrial sectors.

Gas cogeneration under obligation to purchase should thus in part disappear (500 MWe less between 2010 and 2020), with only the facilities of less than 12 MWe able to benefit from the renovation tariff. However, a number of these should go on the market, to take advantage of attractive electricity sale tariffs.

In parallel, a share of the 'Other' cogeneration facilities operating on residues (refinery residues and gas, paper waste, black liquor, etc.) should take advantage of the biomass CFTs to move over to biomass cogeneration. This is particularly the case in the paper industries, which control the forest resource and the production of electricity by cogeneration. Added to installations of new biomass cogeneration facilities on sites previously without cogeneration facilities, the biomass cogeneration capacity should exceed 600 MW in 2020.

Finally, the agri-food industry in particular could benefit from purchasing tariffs to convert existing cogeneration facilities and install new biogas capacities.

The cogeneration capacities installed in this sector should therefore develop in the following manner:

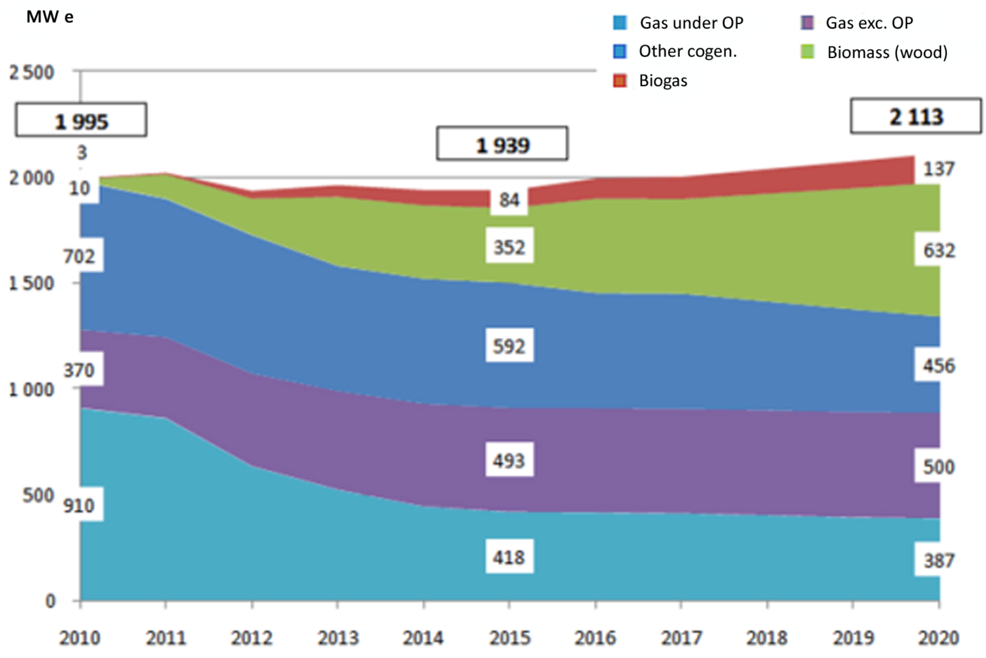

Figure 8 – Development in installed cogeneration capacities in Specific industrial sectors (paper mills, refineries, agri-food)

In the case of steam turbines, the industrial actor may decide either not to modify its installations or to adapt the steam turbine installations to biomass in order to integrate the ERC CFTs or the biomass purchasing tariff. This second choice is economically attractive as it probably requires a smaller investment than for a new installation. We estimate that it could be adopted by about half of industrial actors in this case.

In the case of gas facilities under the OP < 12 MWe, the industrial actor is confronted by the same choices as for the classic industrial sectors, if there is no potential for biogas which can be exploited in the agri-foodstuffs sector on the basis of biogas purchasing tariffs.

In the case of gas facilities under the OP > 12 MWe, the industrial actor is then also confronted by the same alternatives as for the classic industrial sectors. Nevertheless, we have estimated that the operational constraints particular to these sectors may limit the choice of operation on the electricity market (only one facility in three opting for operation on the market). In addition, for the wood/paper sector, conversion to biomass is easier than for the classic industrial sectors due to a greater control of biomass sources.

In the agri-food sector, we estimate that 20% of the technical potential may be achieved by new facilities operating on biogas.

Moreover, the additional technical potential of the wood industry sector (400 MWe), may to a large extent be achieved through the ERC CFTs.

Alternative	Progression rate
Adapt steam turbine facilities to integrate ERC CFTs or the biomass purchasing tariff	50%
No modification compared to the current situation	50%

Table 14 – Progression rate between the different alternatives open to cogenerators in specific industrial sectors, in the case of steam turbines

Alternative	Progression rate
Renovate the facility to benefit from the purchasing tariff	80%
Dismantle the cogeneration facility and go back to a gas boiler	15%
For cogeneration facilities installed in agri-food industries: conversion of facilities to biogas	5%

Table 15 – Progression rate between the different alternatives open to cogenerators in specific industrial sectors, in the case of gas facilities under the OP < 12 MWe

Alternative	Progression rate
Go on the market	30%
Biomass conversion	30%
Dismantle the cogeneration facility and go back to a gas boiler	40%

Table 16 – Progression rate between the different alternatives open to cogenerators in specific industrial sectors, in the case of gas facilities under the OP > 12 MWe

iv. Major heating networks > 12 MWe

In this case, we have hypothesised that the order concerning the renovation of facilities of more than 12 MW installed in heating networks is not published. The renovation tariff is therefore by hypothesis not available to these facilities in our simulations. The gas capacities under the OP currently installed should therefore partially disappear. Some may make the choice of going onto the market to sell the electricity produced.

In addition, the VAT reduced to 5.5% when more than 50% of the heat is produced from renewable and recovered energies (R&R energies) will encourage operators to transfer gas cogeneration facilities to the heating load curve and to diminish gas operating hours.

The installation of more than 150 MW of biomass cogeneration by 2020 should nevertheless not compensate for the dismantling of a part of gas cogeneration facilities. Moreover, 'Other' cogeneration facilities (household waste incineration plants in particular) should remain relatively stable.

It should nevertheless be emphasised that the small number of facilities (nine facilities) comprising this segment mean that "probabilistic" reasoning is of limited value; in fact the decisions taken by a few stakeholders (and in particular the CPCU) will have a significant impact on the development of the capacity of this sector.

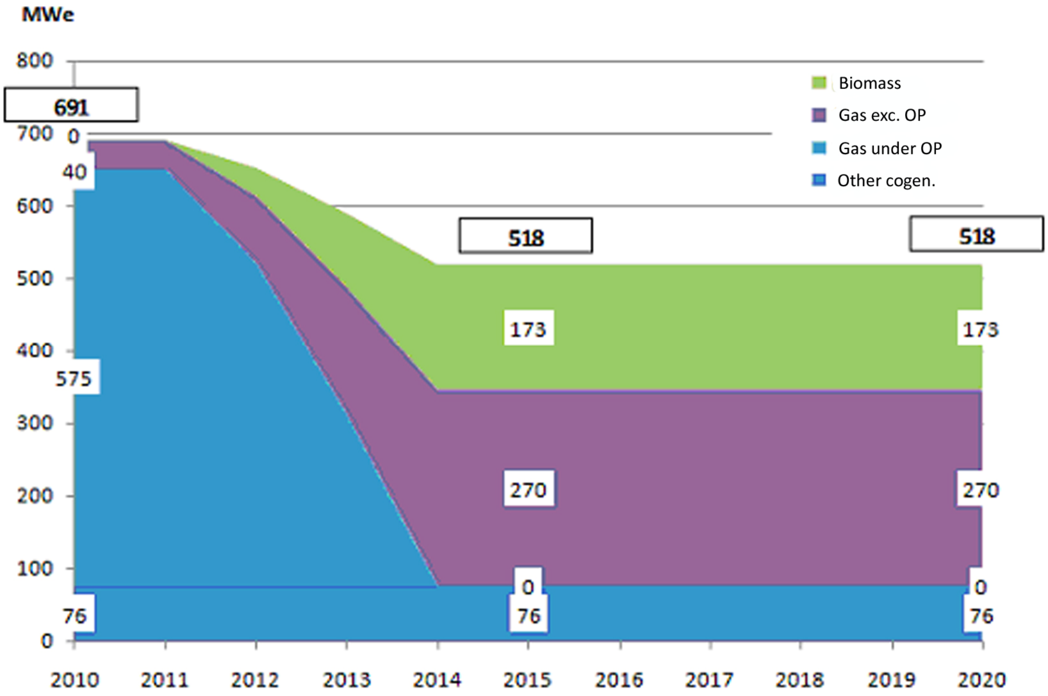

Figure 9 – Development in installed cogeneration capacities in the major heating network sector > 12 MWe

The heating network manager is confronted with the following choices for their cogeneration capacities:

- Move to a biomass boiler to guarantee the heating supply base and put gas cogeneration on the market for the remaining hours (1 500 hours): this alternative, valid for the largest facilities, should be adopted by a significant share of the facilities. This is the alternative which theoretically has the lowest investment (with the exception of dismantling cogeneration) and the highest net present value.
- Move to biomass cogeneration: the investment remains significant and the profitability should be less than in industry due to a lower number of hours, but the benefit offered by the reduced VAT rate should encourage those heating networks already used to managing cogeneration to equip themselves with this technology. We have therefore estimated that this alternative is the second choice for this segment.
- Move to biomass boiler: to a lesser extent, but still to achieve 50% of R&R energies, the heating networks should move their cogeneration to biomass boilers. This has the advantage of representing a smaller investment than in the case of a move to biomass cogeneration,

but does not allow the achievement of stable revenues during 20 years, linked to the resale of electricity at the purchasing tariff.

- Move to gas boiler: a small part of the installed cogeneration capacity should also disappear in favour of gas boilers, in the case where resorting to biomass would not be possible. This is the alternative with the lowest investment, but with an unattractive NPV.

The model is therefore based on the following progression rates:

Alternative	Progression rate
Move to biomass boiler to guarantee the heating supply base and put gas cogeneration on the market for the remaining hours	40%
Move to biomass cogeneration	30%
Move to biomass boiler	20%
Move to gas boiler	10%

Table 17 – Progression rate between the different alternatives open to cogenerators in the major heating network sector > 12 MWe

To these developments in the installed output can be added new biomass cogeneration facilities, with in particular the commissioning of ERC CFTs. The next call for tenders, which only concerns facilities of more than 12 MWe, will also enable the development of biomass cogeneration in this sector.

v. Minor heating networks < 12 MWe

Small scale gas facilities have the possibility of benefiting from the C01R renovation feed-in tariff.

In addition, the VAT reduced to 5.5% when more than 50% of the heat is produced from renewable and recovered energies (R&R energies) will encourage operators to transfer gas cogeneration facilities to the heating load curve and to diminish gas operating hours.

The new networks wishing to function on biomass will probably equip themselves with biomass boilers. The powers in question make them ineligible for the biomass cogeneration tariff.

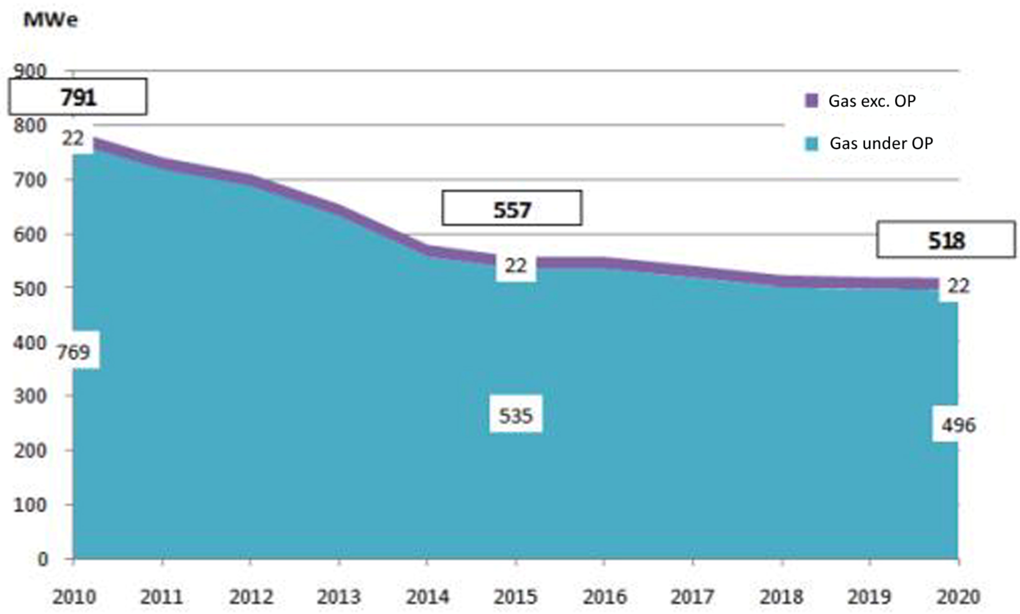

Figure 10 – Development in installed cogeneration capacities in the minor heating network sector < 12 MWe

The heating network manager is confronted with the following choices:

- Renovate the facility to benefit from the C01R purchasing tariff: this alternative is economically profitable but has the disadvantage of not being possible under an R&R energy policy. The NPV determined for this model is however by far the most advantageous, even if, in the same way as for the industrial actors, the risks and operational constraints may act as a brake on this choice. We consider that the majority of facilities will choose this alternative, although the progression rate will be lower compared to the industrial actors for reasons of local political choices in favour of the RE alternative.
- Move to biomass boiler: with Heat Fund aid the investments are contained. While this may translate into a rise in the cost of heat, this option may be chosen for local environmental reasons.

Alternative	Progression rate
Renovate the facility to benefit from the C01R purchasing tariff	60%
Move to biomass boiler	40%

Table 18 – Progression rate between the different alternatives open to cogenerators in the minor heating network sector < 12 MWe

vi. Collective residential and Tertiary > 36 kWe

Cogeneration facilities installed in the Collective residential and Tertiary sectors may benefit from the C01R feed-in tariff.

The move to biomass cogeneration is less easy to imagine, given the location of the facilities (mainly in urban or peri-urban areas).

As in the case with minor heating networks, we have adopted a dominant choice of the renovation feed-in tariff. However, due to the reduction in heat requirements, some facilities will be dismantled. It should also be noted that despite their limited size, some facilities plan to go onto the electricity market.

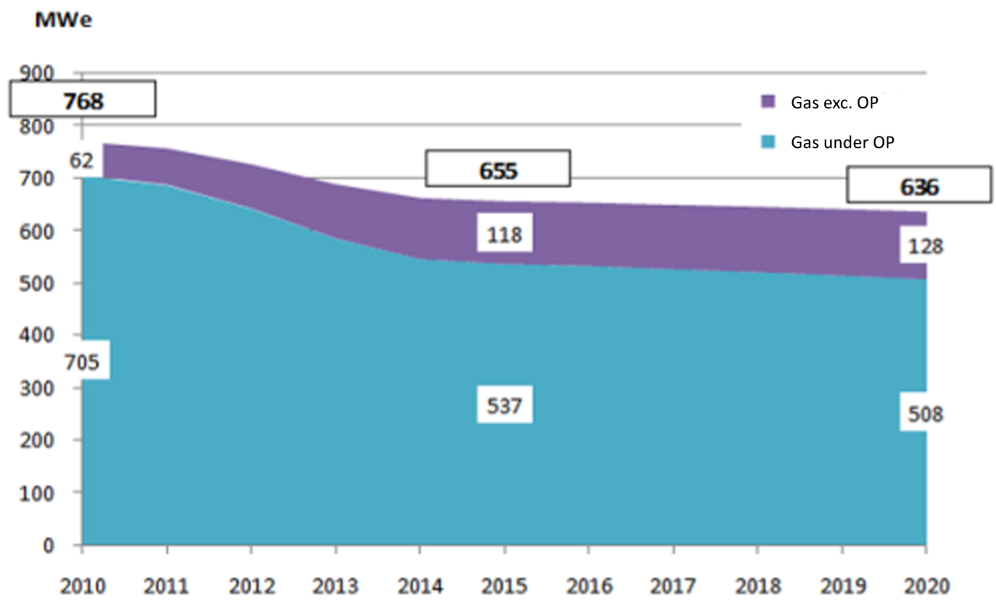

Figure 11 – Development in installed cogeneration capacities in the Collective residential and Tertiary sector > 36 kWe

Alternative	Progression rate
Renovate the facility to benefit from the C01R purchasing tariff	70%
Move to gas boiler	20%
Go on the electricity market	10%
Move to biomass boiler	0%

Table 19 – Progression rate between the different alternatives open to cogenerators in the Collective residential and Tertiary sectors > 36 kWe

vii. Residential < 36 kWe

Gas micro-cogeneration is at an early stage in France. It was therefore difficult to model the penetration of this technology by 2020 in the same way as for the other sectors.

We are here using a model for the penetration of new products into the market, the relative price of micro-cogeneration compared to other technologies enabling us to calculate its penetration into the market.

Part '4 Focus on micro-cogeneration' describes two scenarios for the positioning of the price of micro-cogeneration compared to the heat pump, which is used as the reference technology. We will here assume that micro-cogeneration would have a cost equivalent to that of a heat pump.

Using this hypothesis, we estimate that the total power of micro-cogeneration could achieve around 200 MWe by 2020.

We have made the hypothesis that this installed capacity was essentially under the obligation to purchase. There is an obligation to purchase of 8 euro cents/kWh for micro-cogeneration. However, given the significant administration fees, this tariff is only attractive for a relatively large-scale production of electricity and therefore of heat. In new individual residential properties, heating requirements are low. We therefore make the hypothesis that micro-cogeneration facilities installed in new individual residential properties will not benefit from the purchasing tariff as the low number of operating hours of the appliance in this case will not permit the production of much electricity. However, we consider that in existing residential and in new or existing collective properties, micro-cogenerators would have sufficient operating hours to benefit from the purchasing tariff. That said, auto-consumption being more advantageous than sale, only the non auto-consumed fraction would be sold[15].

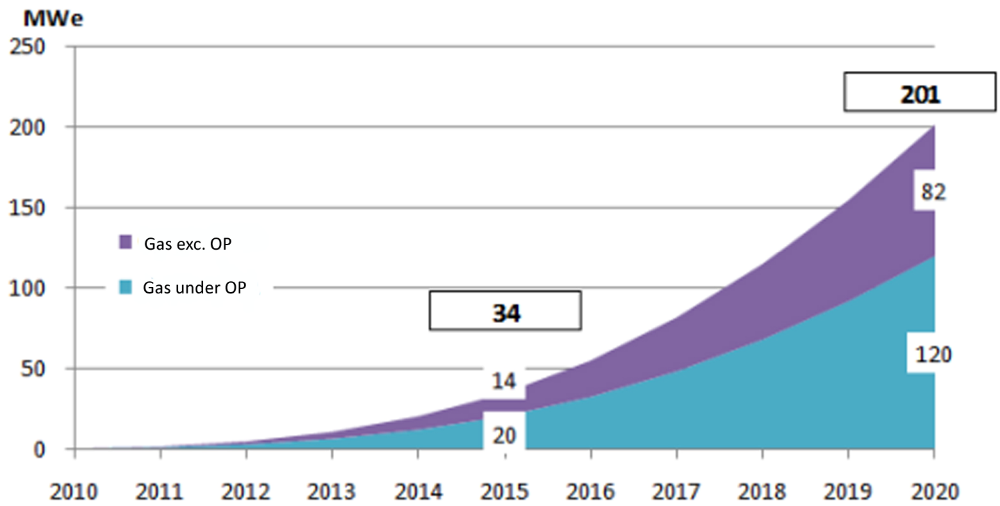

Figure 12 – Development in installed micro-cogeneration capacities in the Residential sector < 36 kWe

[15] We have made the hypothesis that 40% of the electricity produced would be sold (according to interviews). This has an influence on the weight of micro-cogeneration in the SCOPE.

The detail of the economic potential for micro-cogeneration can be found in part '4 Focus on micro-cogeneration'.

3. Overall results

a) Installed power

i. Total economic potential

Overall, and according to our estimations, the cogeneration output should not develop by 2020, but should remain stable or even slightly regress, since it should achieve around 5.7 GWe in 2020.

This apparent stability is due to the combination of two contradictory phenomena: the reduction in the gas cogeneration capacity (down by 1.4 GWe) due to the limitation of the policy of support for gas cogeneration (restriction to facilities of less than 12 MWe) and the progressive development of biomass cogeneration (up by 1.2 GWe) due to a policy of support initiated in the 2000s and adapted on a regular basis. It should be noted that this simulation is strongly conditioned by the economic hypotheses adopted; in other words on one hand the energy price configurations enabling the "profitable" production of electricity from gas, and on the other hand a control of the price of forest biomass.

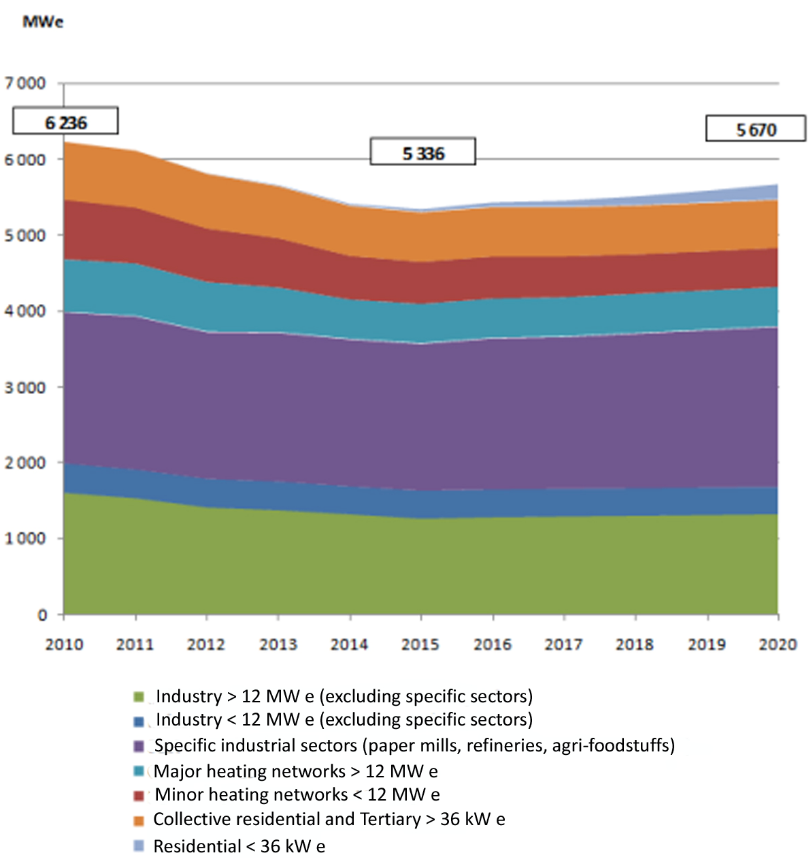

Figure 13 – Total economic cogeneration potential by sector

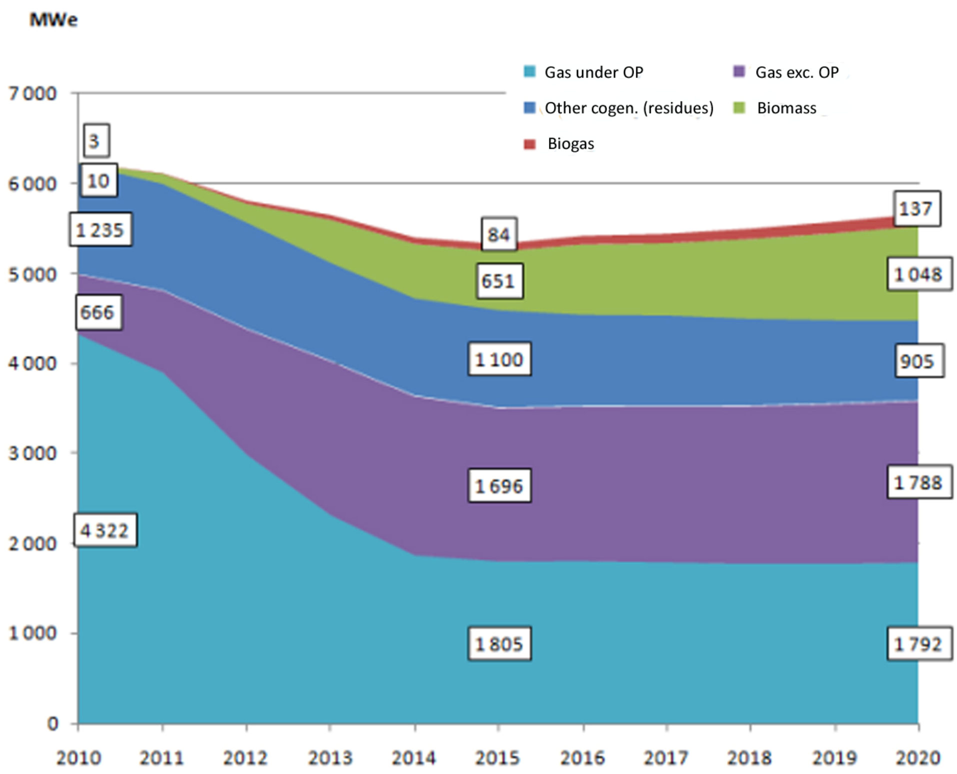

Figure 14 – Total economic cogeneration potential by fuel

If we compare this development of the cogeneration output by 2020 with the technical potential previously determined (cf. Table 8), we can observe that the output remains roughly constant at a level which is around one fifth of the technical potential.

A distribution of this development by activity sector according to the segmentation used in the technical potential shows a regression in most of the activity sectors, but a progression in the individual residential sector (micro-cogeneration effect), in the wood/paper industry (forest biomass effect) and in the greenhouse sector (biogas effect).

	Technical potential	Cogeneration output				
	2020	Installed output 2008		Economic potential 2020		Devel. 2008-2020
	MWe	MWe	% technical potential	MWe	% technical potential	
Residential (exc. HN)	12 190	329	3%	470	4%	↗
Collective	6 135	329	5%	285	5%	↘
Individual	6 055	0	0%	185	3%	↑
Tertiary (exc. HN)	3 705	449	12%	370	10%	↘
Health	475	252	53%	210	43%	↘
Education - Research	585	66	11%	55	9%	↘
Co-housing	315	0	0%	0	0%	
Sport-leisure	365	53	15%	45	12%	↘
Shops	680	6	1%	5	1%	↘
Cafes, hotels, restaurants	320	0	0%	0	0%	
Offices	840	15	2%	10	1%	↘
Transport (stations, airports)	125	57	46%	45	37%	↘
Heating networks	2 920	1 513	52%	1 035	35%	↘
Industry (exc. HN)	8 950	3 930	44%	3 635	41%	↘
Agri-foodstuffs (inc. sugar refineries)	1 075	619	58%	435	40%	↘
Chemicals (inc. elastomers)	1 950	1 339	69%	1 205	62%	↘
Paper/cardboard	970	872	90%	980	101%	↗
Refineries	1 345	571	42%	540	40%	↘
Automobile equipment mfrs	365	379	104%	340	94%	↘
Others (aeronautical, electronic, etc.)	3 245	150	5%	135	4%	↘
Others (exc. HN)	2 575	114	4%	160	6%	↗
inc. greenhouses	2 575	112	4%	160	6%	↗
TOTAL	30 340	6 336	21%	5 670	19%	↘

Table 20 – Development of the output by sector by 2020

b) Energy production

To calculate the energy production linked to the economic potential, the study has been based on the number of hours of operation resulting from the different choices of the cogenerators for each of the sub-sectors.

hrs/year	Biomass	Biogas	Gas excluding OP	Gas under OP	Other cogen. (residues)
Industry > 12 MWe (excluding specific sectors)	5 500	-	2 000	3 150	4 000
Industry < 12 MWe (excluding specific sectors)	-	-	2 000	3 150	-
Specific industrial sectors (paper mills, refineries, agri-foodstuffs)	5 000	5 000	2 000	3 150	5 000
Major heating networks > 12 MWe	3 350	-	1 500	3 350	3 350
Minor heating networks < 12 MWe	-	-	1 500	3 350	-
Collective residential and Tertiary > 36 kWe	-	-	1 500	3 350	-
Residential < 36 kWe			Cf. Table 25, page 56		

Table 21 – Hypothesis for hours of operation equivalent to full charge of cogeneration facilities according to fuel for each of the selected key sectors

The profile for the development of electricity production therefore follows that observed for the installed electrical power (cf. Figure 14 above):

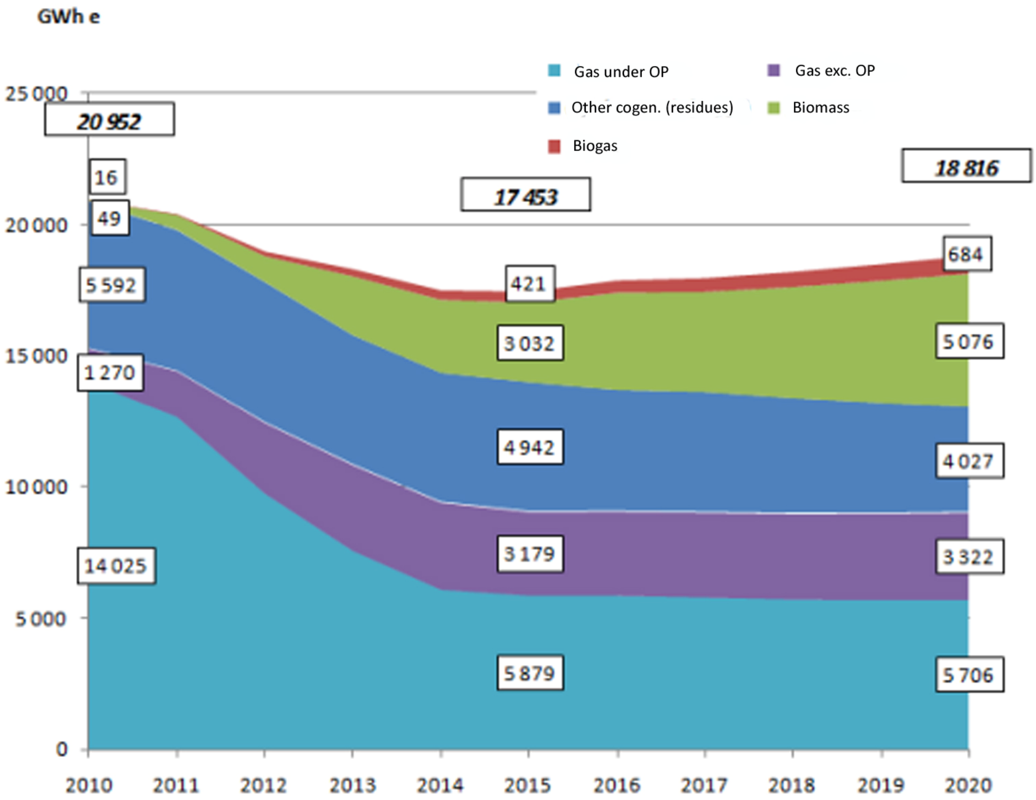

Figure 15 – Total electrical production of the economic potential of cogeneration by fuel

The profile for the development of heat production changes, however. The H/E ratios are no longer the same for the gas and biomass technologies in particular: for a given electrical power, a biomass cogeneration facility delivers much more heat than a gas cogeneration facility. The strong progression of biomass and the reduction in gas will therefore lead to an overall increase in the production of heat:

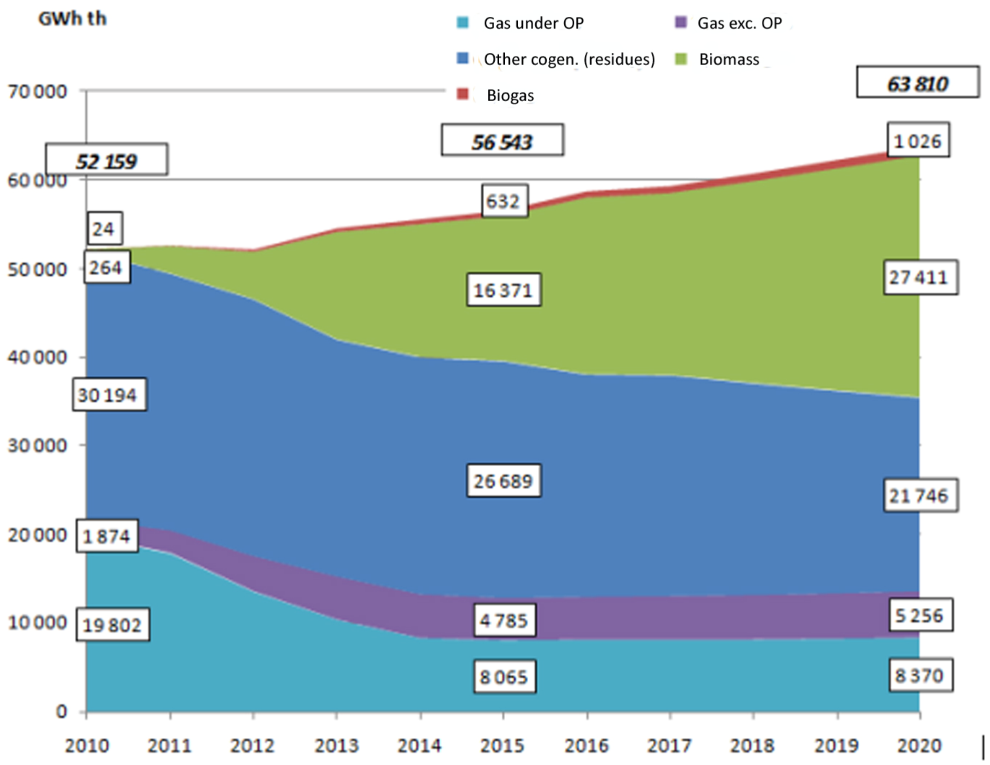

Figure 16 – Total heat production of the economic potential of cogeneration by fuel

c) CO_2 emissions avoided and primary energy savings

CO_2 emissions avoided

As cogeneration combines at the same time the production of heat and the production of electricity, this technology enables certain gains in terms of CO_2 emissions and primary energy.

Regarding CO_2 emissions, the production of electricity by cogeneration permits the avoidance of resorting to another means of electricity production. Given the technical characteristics of cogeneration, and in particular its flexibility, it has been considered in this study that cogeneration would in all cases substitute for a combined gas cycle. The associated emissions factor has been set at equal to 420 $kgCO_2/MWh$ e[16], whatever the number of hours of operation of the cogeneration facility.

As cogeneration produces not only electricity, but also, and as a priority, heat, the whole of the fuel used may not be accounted for in the production of electricity. In order to calculate an emissions factor linked to the production of electricity only, the share of emissions linked to the production of

[16] The replaced production method has been assumed systematically to be a combined gas cycle with a 55% yield; according to Decision 2007/589/EC[4], the corresponding CO_2 content is therefore: 231 [$kgCO_2$/MW h]/55% = 420 [$kgCO_2$/MW h].

heat has been removed. In order to do this, the heat has been considered as being produced by a classic boiler.

Given the yield hypotheses adopted for the different technologies, the emission factors for the production of electricity by cogeneration are therefore as follows:

	Hypotheses						Results	
	Fuel	Heat only	Cogeneration 2010		Cogeneration 2020		Cogen. elec. 2010	Cogen. elec. 2020
	EF $kgCO_2/MWh$	• ref.	• elec.	• heat	• elec.	• heat	EF $kgCO_2/MWh$	EF $kgCO_2/MWh$
Biomass	0	86%	14%	76%	14%	76%	0	0
Biogas	0	70%	40%	40%	42.5%	42.5%	0	0
Gas (Industry and HN > 12 MW)	231	90%	32%	48%	34%	51%	337	294
Gas (HN < 12 MW and Coll. & Tert.)	231	90%	36%	45%	38%	48%	321	283
Other cogen.	264	80%	14%	76%	14%	76%	95	95

Table 22 – Emission factors (EF) of CO_2 from the production of electricity by cogeneration depending on fuel (sources: Decision 2007/589/EC [4] and Annex II of Directive 2007/74/EC [2])

The CO_2 emissions avoided by cogeneration are therefore calculated according to the following formula:

CO_2 avoided =
emissions from the separate production of electricity
- emissions from the production of electricity by cogeneration

Equation 2 – Formula for the calculation of CO_2 emissions avoided

The methodology used for the calculation of CO_2 linked to the production of electricity by cogeneration and the emissions avoided is described in Annex 10 of this report.

As the installed gas output diminishes little by little in favour of biomass, the emissions avoided increase, going from 3 200 Mteq of CO_2 avoided in 2010 to more than 4 600 Mteq of CO_2 in 2020, as shown by the following figure.

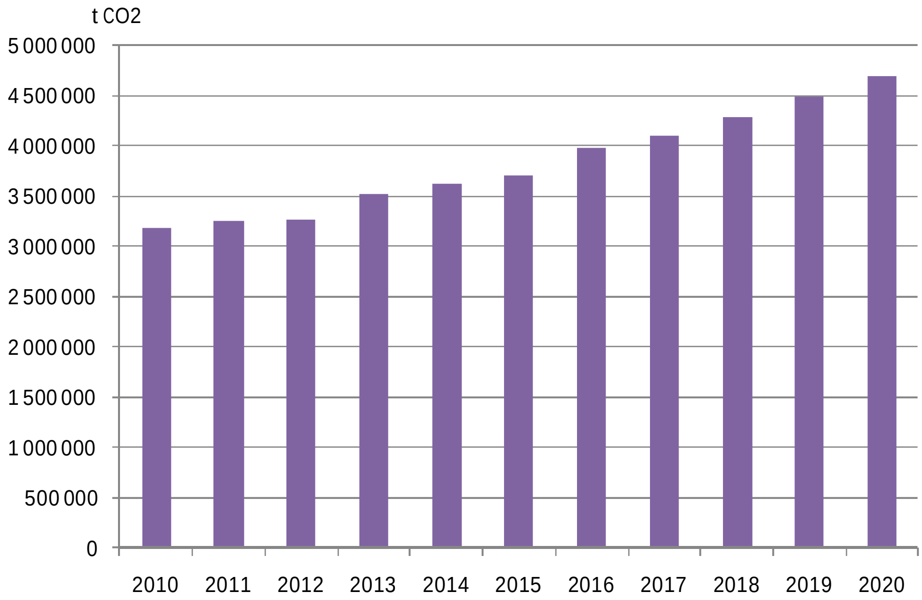

Figure 17 – CO_2 emissions avoided by cogeneration

Primary energy savings

Regarding primary energy savings, an increase in the savings theoretically realised is also observed. This results from the hypotheses and calculation methodology given by the Directive. For each cogeneration technology, two reference yields are defined; one for the separate production of heat with the same fuel as the cogeneration, and the other for the separate production of electricity, also using the same fuel.

For biomass, the gap between the reference yields and the cogeneration yields is greater than for gas, leading to theoretical primary energy savings which are higher in the case of biomass. As the installed capacity of biomass cogeneration increases, the methodology and hypotheses adopted lead to an increase in the primary energy saved.

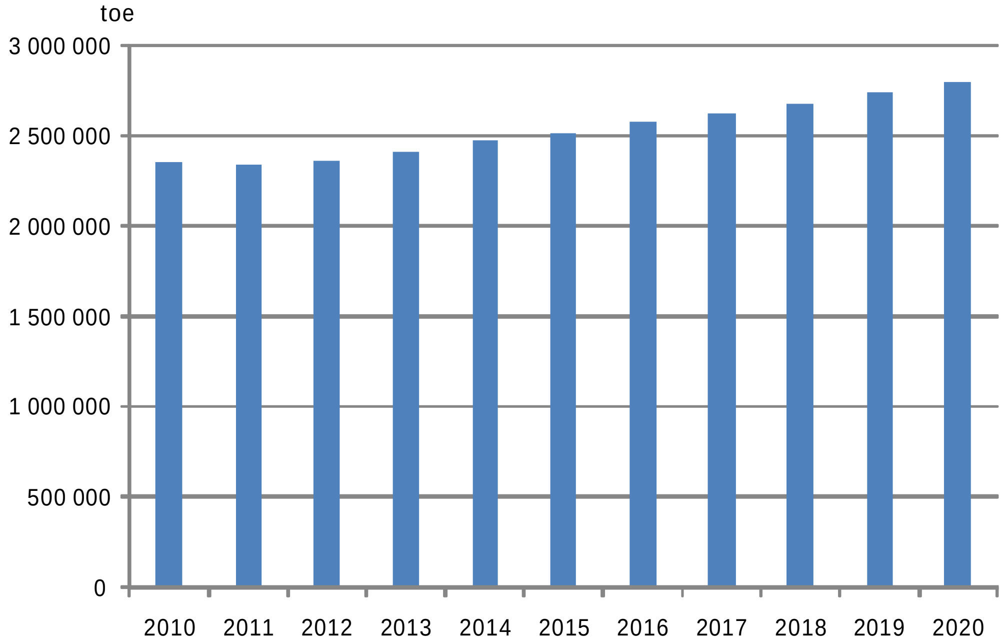

Figure 18 – Theoretical primary energy savings realised with cogeneration

The methodology used for the calculation of the primary energy savings is described in Annex 11 of this report.

The increase in cogeneration, and in particular in biomass, enables an increase in primary energy savings (Figure 18), but also in the consumption of fuels linked to this technology by 2020 (Figure 19).

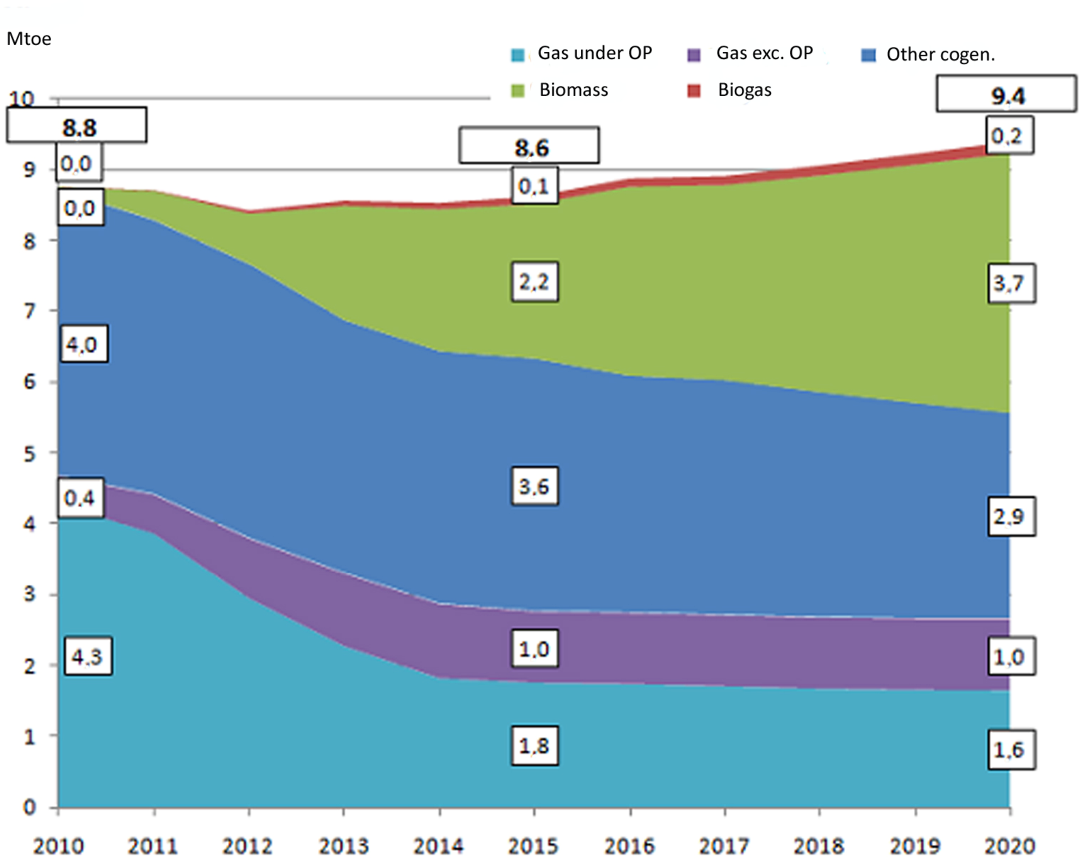

Figure 19 – Developments in the consumption of fuel by the cogeneration sector[17]

d) Investment cost and weight on the SCOPE

Investment cost

To achieve the total economic potential, a significant investment will be necessary to renovate or install new facilities. This means that between 2010 and 2020, nearly 5 billion euros must be invested to renovate existing facilities and to install new RE micro-cogeneration and cogeneration facilities in order to achieve an installed capacity of 5 670 MWe in 2020.

The tables below give an estimation of the investment by sector and by type of operation.

The hypotheses made to calculate these levels of investment are described in Annex 12.

[17] The values resulting from our top-down model have been corrected in order to correspond to the statistical data of SOeS [13].

Total investment (m€)	TOTAL 2010-2020
Industry > 12 MWe (excluding specific sectors)	771
Industry < 12 MWe (excluding specific sectors)	96
Specific industrial sectors (paper mills, refineries, agri-foodstuffs)	2 010
Major heating networks > 12 MWe	714
Minor heating networks < 12 MWe	150
Collective residential and Tertiary > 36 kWe	181
Residential < 36 kWe	1 007
TOTAL	4 928

Table 23 – Investment by sector to achieve the economic potential of cogeneration

Total investment (m€)	TOTAL 2010-2020
Conversion cost gas -> biomass cogen. (m€)	1 011
Conversion cost other cogen. -> biomass cogen. (m€)	276
Conversion cost cogen. -> boiler (m€)	-62
Overhaul cost gas cogen. (m€)	184
Renovation cost gas cogen. (m€)	435
Construction cost biomass cogen. (m€)	1 977
Construction cost gas micro-cogeneration cogen. (m€)	1 007
Construction cost biogas cogen. (m€)	100
TOTAL	4 928

Table 24 – Investment by type of operation and by fuel to achieve the economic potential of cogeneration

Weight of cogeneration on the SCOPE

The realisation of the economic potential of cogeneration as modelled in this study occurs through the increase in the number of biomass cogeneration facilities under the obligation to purchase and by a certain number of existing gas cogeneration facilities moving to the renovation tariff. These support measures have a cost on the SCOPE, evaluated at around € 900 m in 2020 (cf. Figure 21). The reduction in the weight of support for gas cogeneration facilities should be more than compensated by the increase in the weight of biomass, around € 530 m in 2020 (cf. Figure 20).

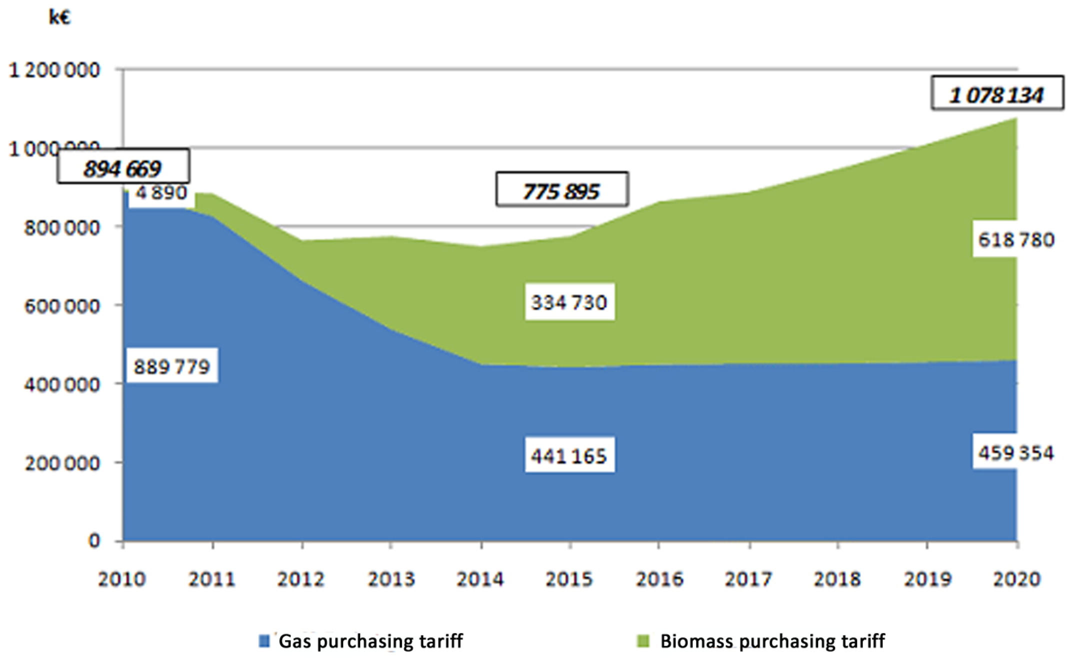

Figure 20 – Weight of cogeneration on the SCOPE: distribution by system

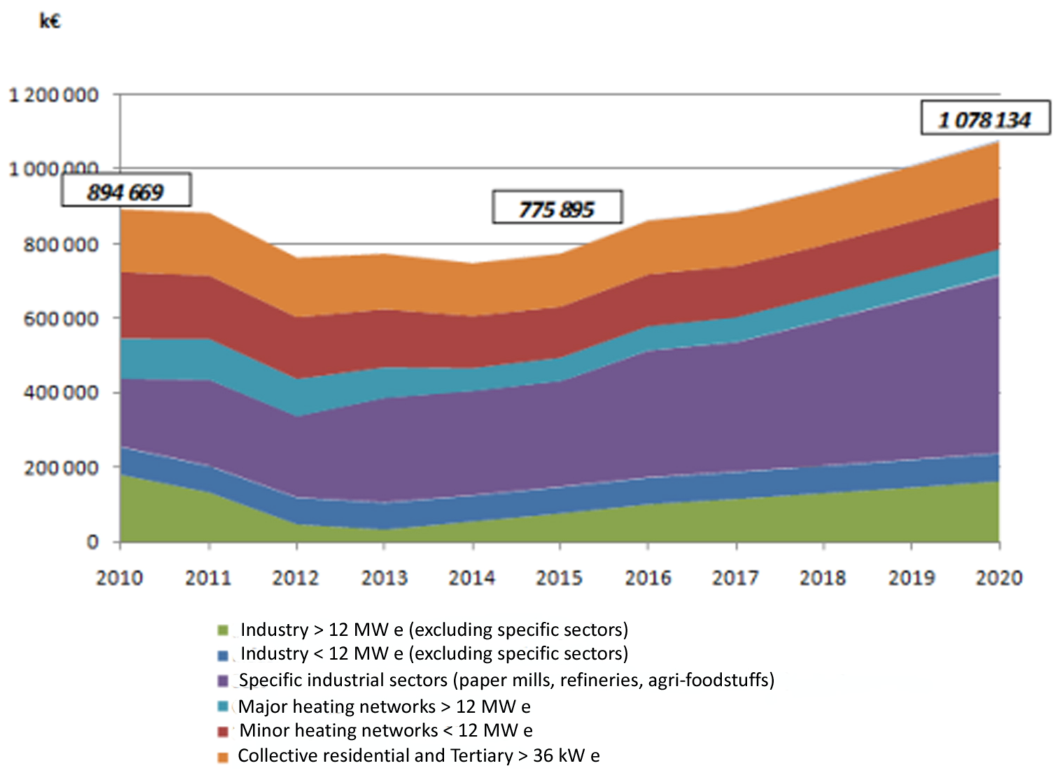

Figure 21 – Weight of cogeneration on the SCOPE: distribution by sector

4. Focus on micro-cogeneration

The micro-cogeneration market is just beginning to emerge in France and the prospects for development are thus very unclear. A detailed description of the regulatory and economic context of micro-cogeneration can be found in Annex 8.

Two scenarios for development have been drawn up according to the costs of micro-cogeneration. Here we are using as a model of market penetration a model for the growth of new products of S type curve. The potential market or the saturation of the market is defined according to the price established for micro-cogeneration compared to other technologies.

In both hypotheses, we assume that the ESCs and the tax credit (with a rate of 25%, identical to that for heat pumps) are implemented for micro-cogenerators. The difference comes from the future cost of micro-cogenerators.

Low hypothesis (cost close to that of a heat pump)

In the case where micro-cogeneration would have a cost equivalent to that of a heat pump, we make the hypothesis that its rate of penetration in new construction where only the most efficient technologies are authorised (electric heat pump, boiler + CESI) could eventually represent one tenth of the market in the individual residential context. Heat pumps are already known and have a positive RE image. Currently, only the upper social categories seeking new technologies will be placed to opt for micro-cogeneration (or 2.5% of the market for the replacement of existing boilers, on the basis of [23]).

In the case of multi-occupation housing, we assume a basic dimensioning of one micro-cogenerator (or MCHP) for 10 homes, in order to optimise the number of operating hours of the MCHP. In this case, micro-cogeneration would be a financially attractive technology. We assume a potential market of 10% in new residential construction. In existing collective housing, however, we assume a low potential market share of 2.5%, as the solution remains expensive compared to more conservative solutions (condensing boiler).

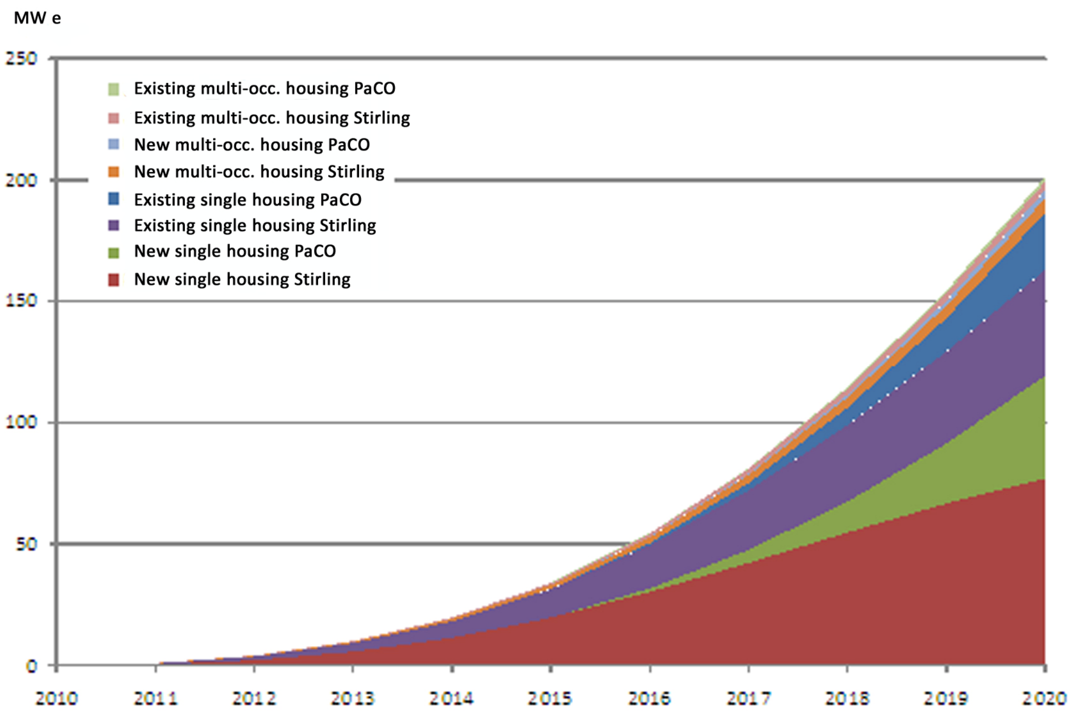

Figure 22 – Share of micro-cogenerators installed (low hypothesis)

High hypothesis (cost less than that of a heat pump)

In the case where micro-cogeneration would have a tariff between that of heat pumps and condensing boilers + CESI, its positioning compared to other authorised technologies in new construction would allow it ultimately to achieve 25% of the market. In existing properties, we assume a market share of the order of 10%. In the case of multi-occupation housing, as the cost of the technology is more attractive, we assume a basic dimensioning of one micro-cogeneration boiler to 5 homes.

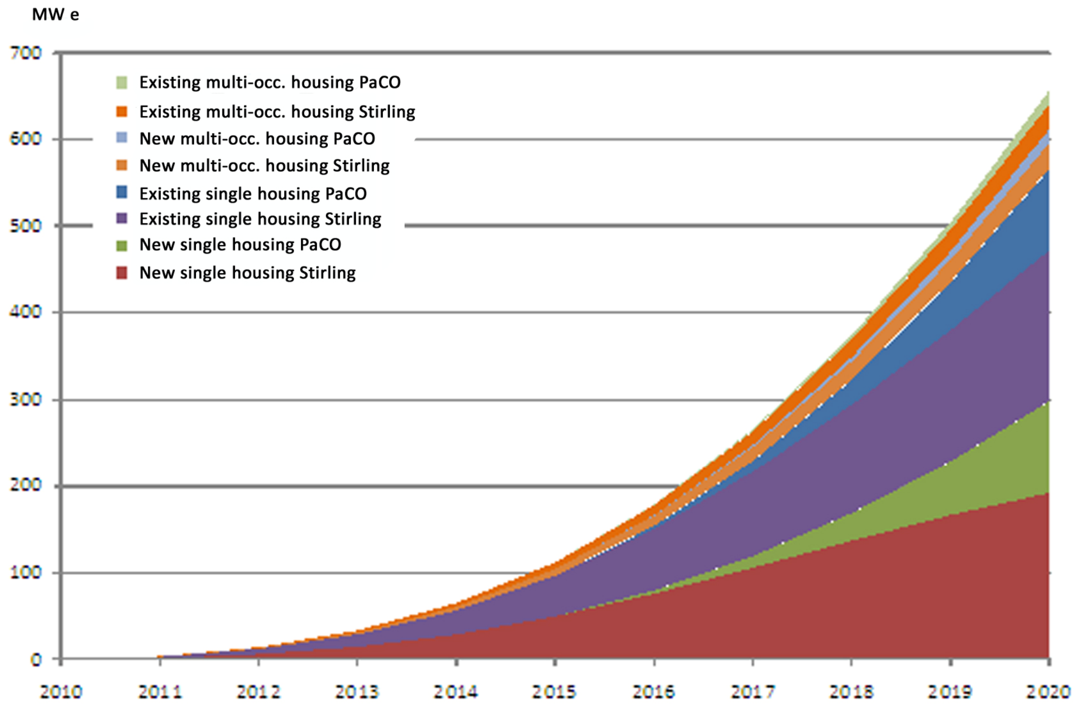

Figure 23 – Share of micro-cogenerators installed (high hypothesis)

We assume that fuel cells should appear on the market from 2015 with a development similar to that of micro-cogeneration boilers. The electrical power of each unit is set at 1 kWe for Stirling micro-cogeneration boilers and 2 kWe for fuel cells.

Here, the specific development of RE-based micro-cogenerators is not taken into account. Their development should be marginal unless incentive measures are introduced.

In terms of number of operating hours, the hypotheses for full charge equivalent operation are as follows:

	hrs/year	hrs/year (5 home dimensioning case)
New single family house	1 000	
Existing single family house	2 500	
New multi-occupation housing	4 200	3 300
Existing multi-occupation housing	5 500	4 300

Table 25 – Hypothesis for operating hours equivalent to full charge of micro-cogeneration

From these hypotheses we obtain electricity production for the two cases:

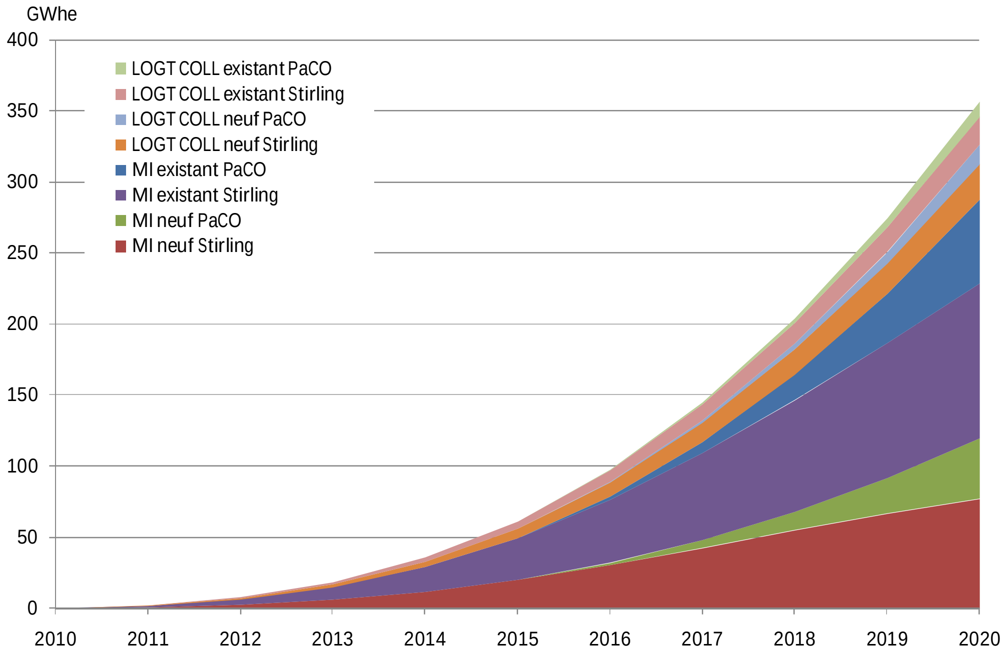

Figure 24 – Electrical production of micro-cogenerators installed (low hypothesis)

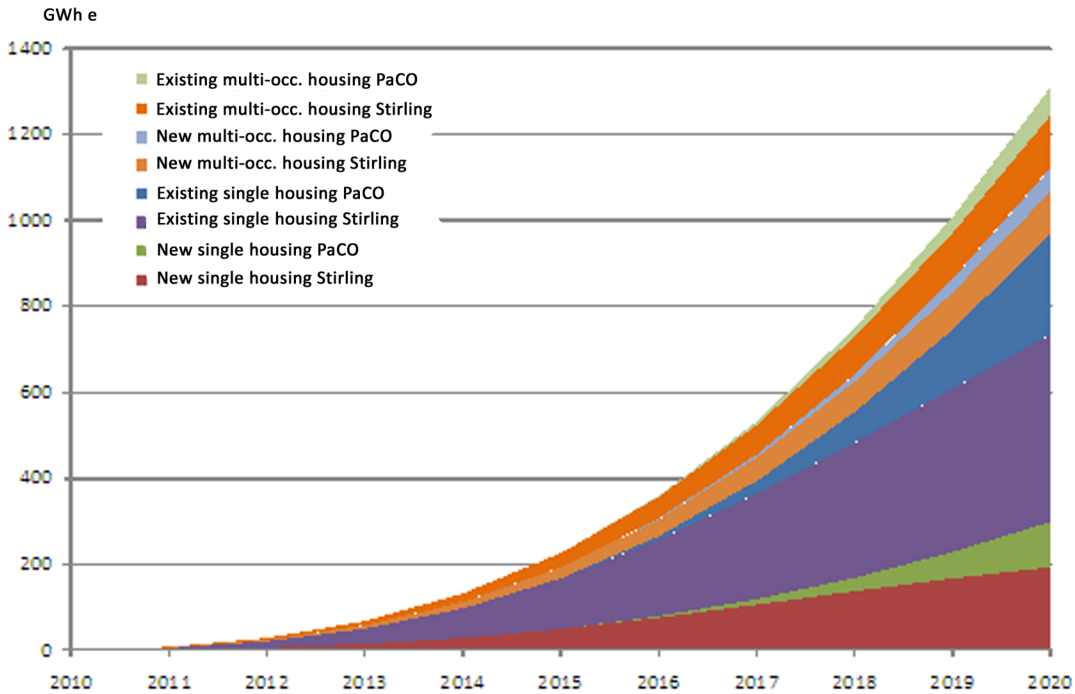

Figure 25 – Electrical production of micro-cogenerators installed (high hypothesis)

5. Focus on biomass

Our model of the development of biomass cogeneration is based on a dual approach.

On one hand we have estimated and discussed with interested parties a rate for the conversion of an existing cogeneration facility (gas or residues) to biomass cogeneration in a "bottom-up" approach. We have previously described this in paragraph III.2 b) 'Results by key sector'.

On the other hand, we have carried out a macro analysis based on the implementation of the first biomass call for tenders ('ERC 1') and on a target implementation rate of around 70% for biomass calls for tenders ERC 2, 3 and 4, on the basis of interviews carried out and brakes identified.

In addition, we have made the hypothesis that the volume of facilities concerned by the purchasing tariff will be taken from the amount for the ERC CFTs.

This leads us to the following estimations:

Wood	ERC 1	ERC 2	ERC 3	ERC 4 and purchasing tariff	TOTAL
Conditions	> 12 MWe	> 5 MWe	> 3 MWe	> 12 MWe and 5-12 MWe	-
Project scope	232 MWe	363 MWe	266 MWe	800 MWe	1 661 MWe
Projected implementation	93 MWe	254 MWe	186 MWe	560 MWe	1 093 MWe
Year of commissioning	2010	2012	2015	2016-2020	-

Table 26 – Objectives and projected implementations for ERC biomass calls for tender taken into account in the study

Assuming that 50% of this implementation comes from new cogeneration facilities, and 50% from facilities carrying out a change of fuel, the macro analysis agrees with the "bottom up" analysis.

This dual approach has enabled us to estimate the potential in terms of biomass cogeneration in the different sectors studied, both regarding fuel changes and new facilities, for wood and biogas.

The following two paragraphs give the detailed results by energy source.

Wood

Forest biomass cogeneration should develop, essentially through the biomass CFTs, in three main key sectors identified in this study:

- Industry > 12 MWe (excluding specific sectors)
- Specific industrial sectors (paper mills, refineries, agri-foodstuffs)

- Major heating networks > 12 MWe

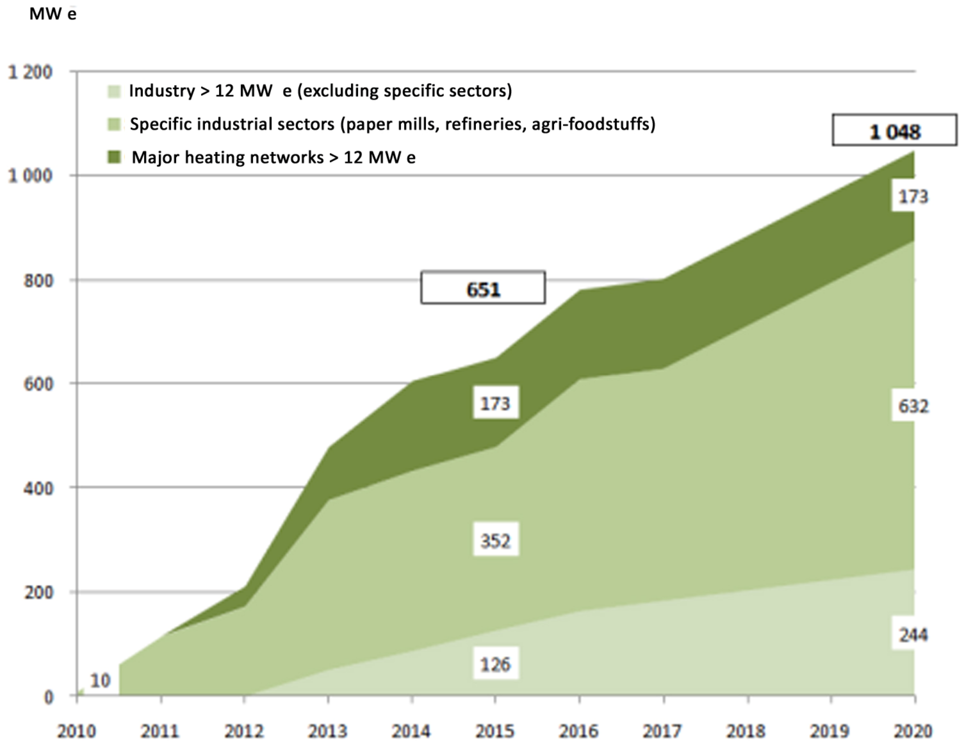

Figure 26 – Total economic biomass cogeneration potential by activity sector

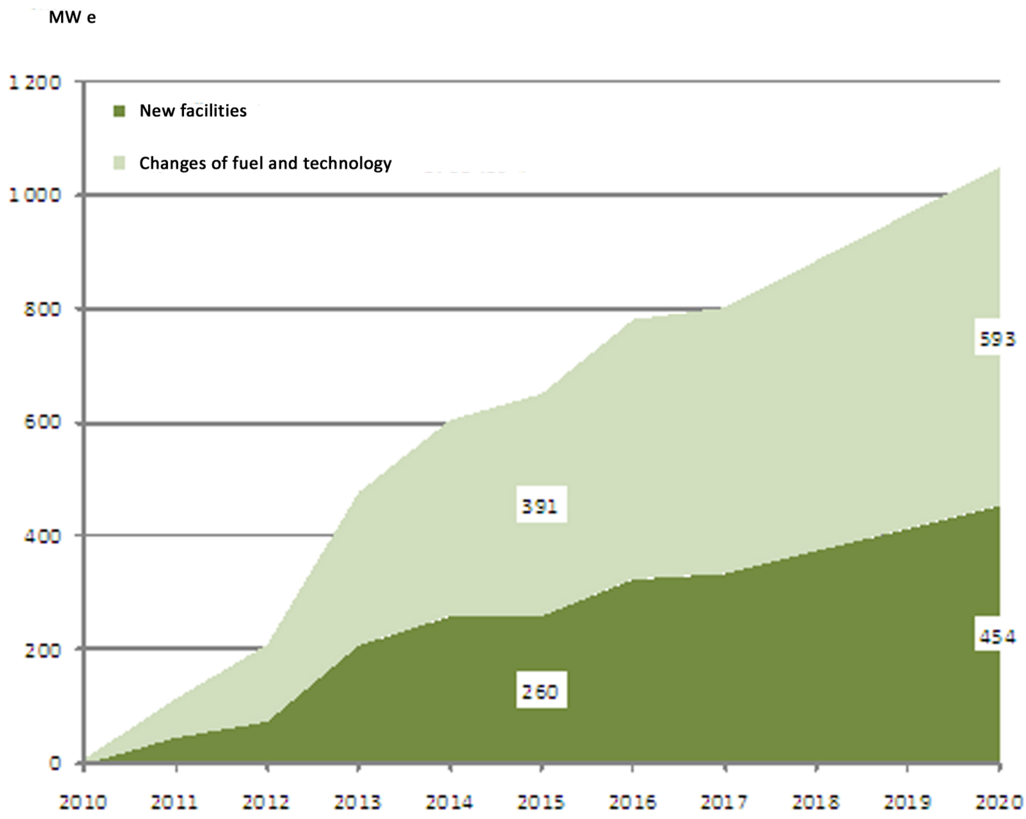

Figure 27 – Total economic biomass cogeneration potential: new facilities and changes in fuel and technology

Biogas

The potential for the development of biogas cogeneration remains quite low. Several solutions allow the use of this gas, which, produced relatively easily from sewage sludge from wastewater treatment plants or from waste (farms, household waste, etc.) is of high energy quality. It may be:

- Used directly on site (in particular by cogeneration)
- Injected into the network
- Used in captive vehicle fleets (e.g. household waste collection trucks).

These two latter solutions seem most advantageous from the energy and environmental point of view: they enable the direct replacement of a fossil fuel by an R&R energy fuel.
Nevertheless, in certain cases such as the agri-food industry or in greenhouses, the direct use of biogas on site may prove to be attractive. It would then replace the use of fossil fuel to meet an existing heat requirement. A capacity of around 140 MW may thus be installed by 2020 in these sectors.

Among these sectors, it is in the specific industrial sectors where the largest share of biomass cogeneration power should be installed. This would relate to industrial actors controlling the forest resource and/or the production of electricity by cogeneration.

Overall, we estimate that more than 1 GWe of biomass cogeneration should be installed by 2020 and should produce more than 27 TW h of heat per year (2 350 Mtoe). This calculation is based on the specific hypotheses (in particular the yields of facilities and the number of operating hours) which we have previously described. This is broadly in line with the targets stated in the Heat PPI, even if it is below the cumulative target of the ERC CFTs (1.7 GWe). This remains consistent with the identification of the brakes on development for biomass cogeneration (cf. part IV, paragraph a), page 69)

It should be noted that this differs from the target for the production of electricity from biomass mentioned in the Electricity PPI (2.3 GWe).

6. Sensitivity study

A sensitivity study has been carried out according to the following scenarios:

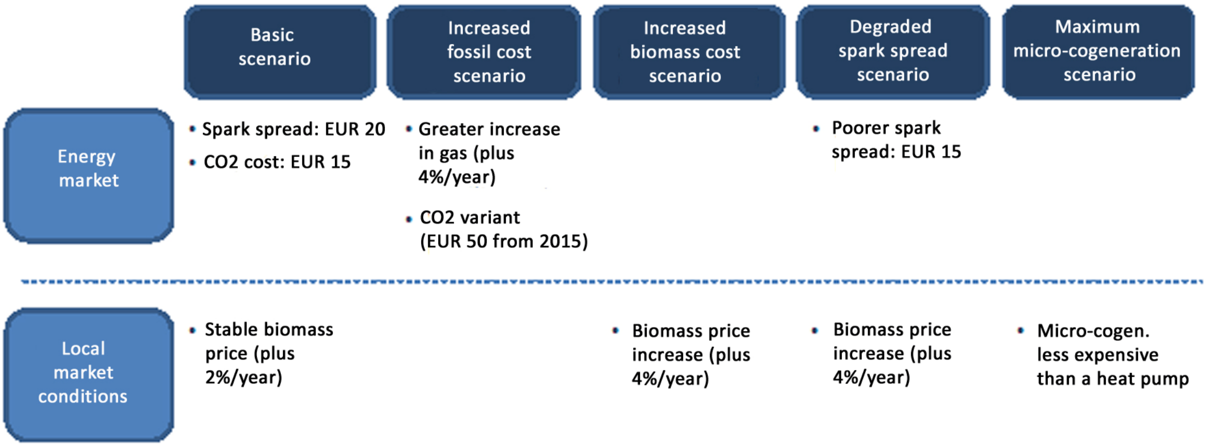

Figure 28 – Scenarios modelled for the sensitivity study

The results by scenario are as follows:

Increased fossil fuel cost scenario

In a scenario where gas increases by 4% annually, and the price of CO_2 moves to € 50 per tonne from 2015, gas cogeneration should undergo a more significant reduction than in the basic scenario. In this scenario, the overall reduction in gas is 1.9 GW compared to 2010, or a reduction of an additional 450 MW.

In addition, biomass penetration is stronger in this scenario, particularly due to its greater attractiveness than gas. It achieves 1.25 GW in 2020, or 250 MW more than in the initial scenario.

Overall, the reduction between 2010 and 2020 of the total installed cogeneration capacity is 800 MWe.

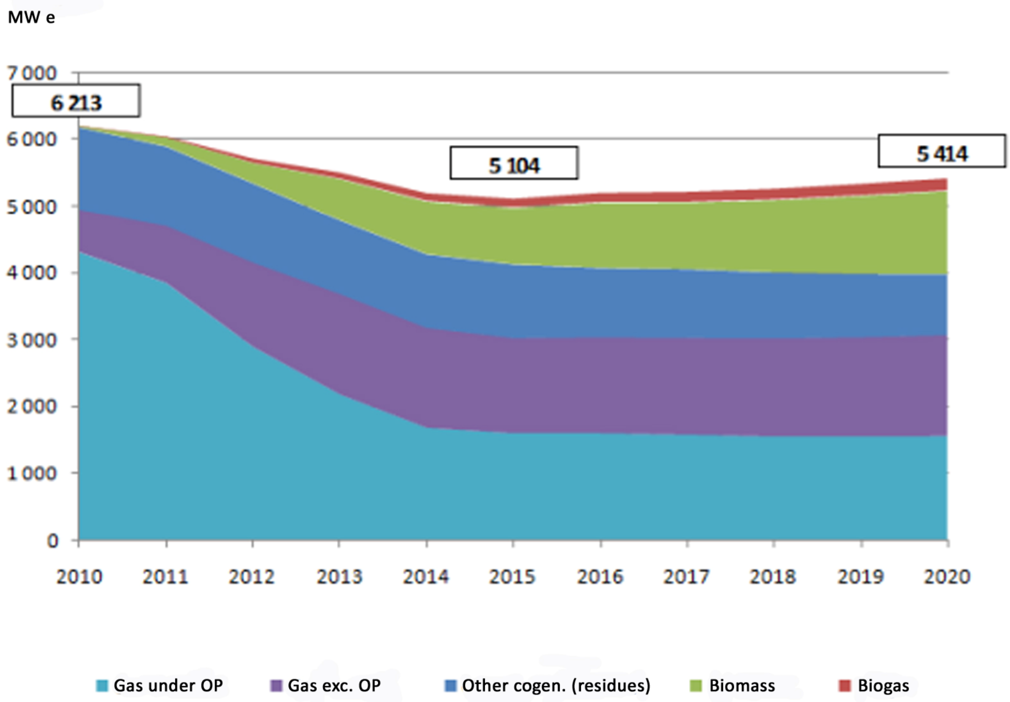

Figure 29 – Increased fossil fuel cost scenario: economic potential of cogeneration by fuel

Increased biomass cost scenario

In this scenario, the reduction in gas cogeneration capacity is more contained than in the reference scenario. Compared to the basic scenario, there would be a much lower rate of conversion of facilities from gas cogeneration to biomass cogeneration, since biomass would become less attractive and more cogenerators would prefer to remain with gas. The installed gas cogeneration power in 2020 in this scenario would therefore be lower by approximately 1.3 GW than in 2010.

The penetration of biomass and biogas are also lower than in the basic scenario. However, the installed power still progresses in accordance with the model used, by 700 MW compared to 2010.

Overall, the reduction between 2010 and 2020 of the total installed cogeneration capacity is nearly 800 MWe.

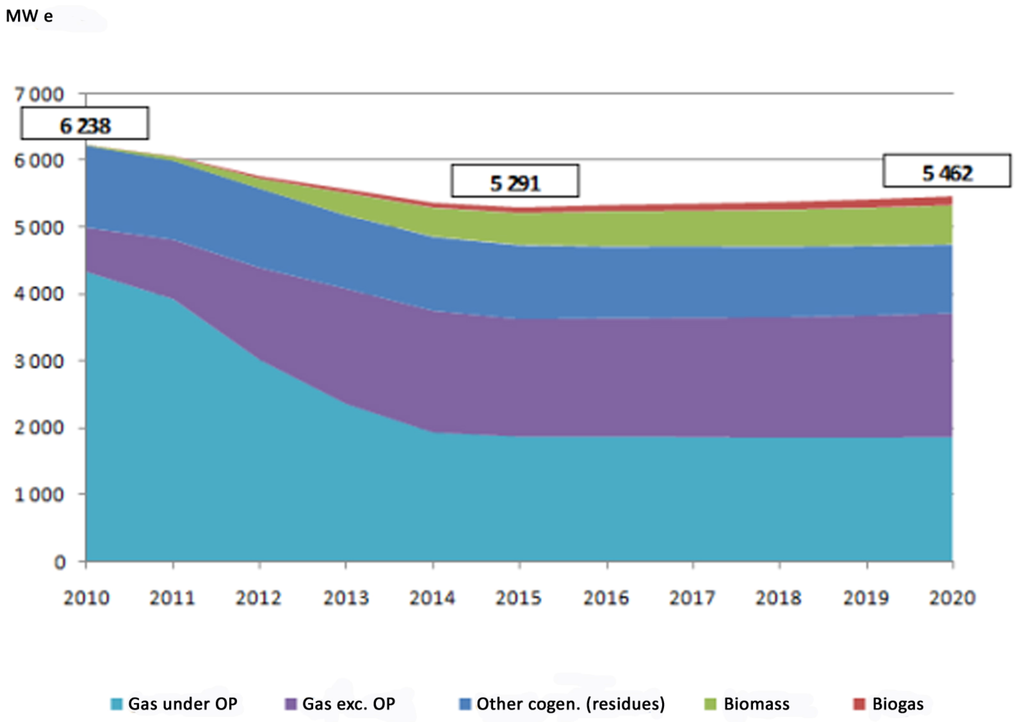

Figure 30 – Increased biomass cost scenario: economic potential of cogeneration by fuel

Degraded spark spread scenario

With less interest in going onto the electricity market, gas cogeneration facilities will be increasingly suppressed in this scenario. The overall reduction in the installed gas cogeneration capacity will therefore be around 1.9 GW between 2010 and 2020.

Given that operating gas cogeneration on the market is less attractive, biomass cogeneration becomes more attractive in this scenario. The total installed biomass and biogas cogeneration power therefore increases between 2010 and 2020 by nearly 1.3 GW. It is above all in heating networks and specific industries that the model predicts a more pronounced choice for biomass.

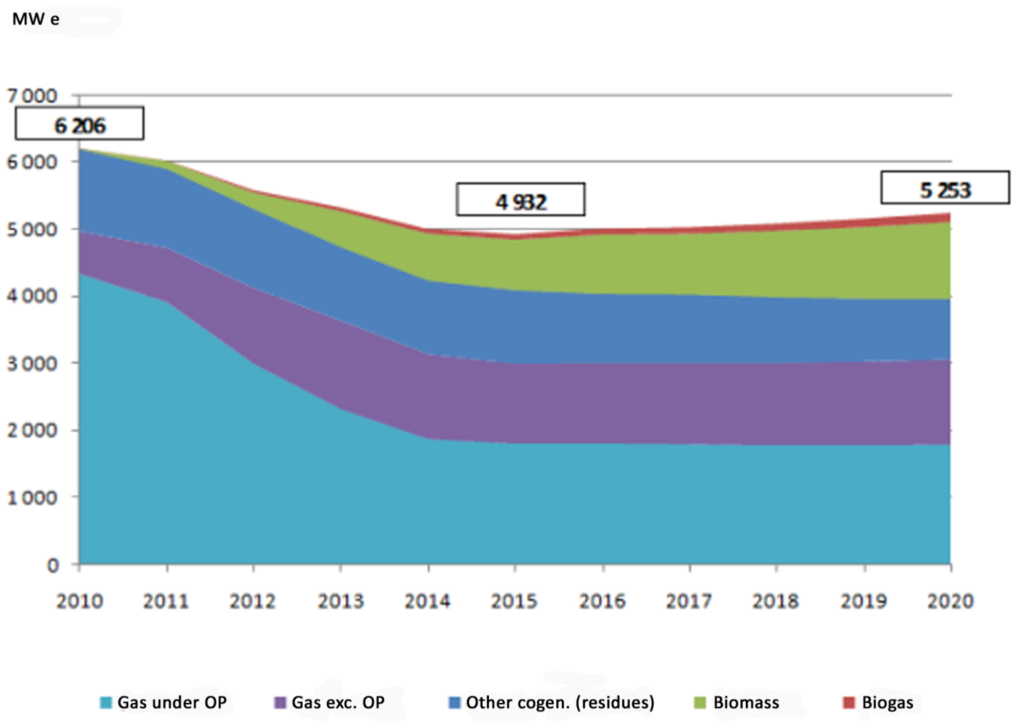

Figure 31 – Minimum cogeneration scenario: economic potential of cogeneration by fuel

Maximum micro-cogeneration scenario

In this scenario, micro-cogeneration increases strongly, to attain more than 650 MWe in 2020. This is the high hypothesis for the development of this technology (cf. Figure 23). More than 350 MWe relates to 'gas excluding OP': this refers to new single family houses whose heat requirements are low and for which it is not attractive to resort to the obligation to purchase. The remaining 300 MWe are under the OP: these installed capacities correspond to micro-cogenerators installed in multi-occupancy housing and existing single family houses.

The installed capacities in other fuels do not change.

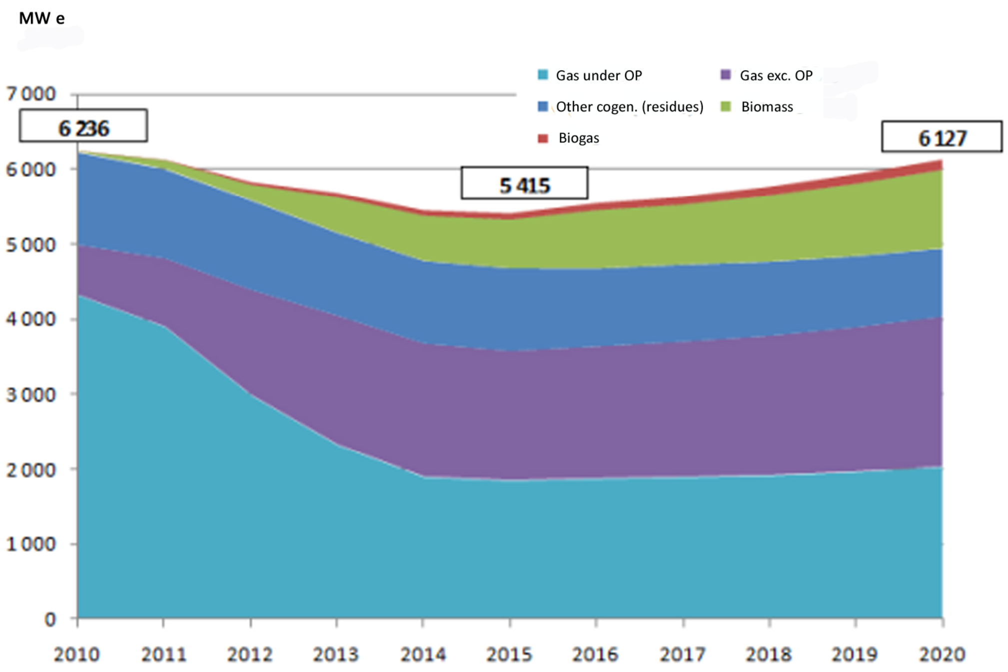

Figure 32 – Maximum micro-cogeneration scenario: economic potential of cogeneration by fuel

7. Special case of cooling networks

Cooling networks may, from a theoretical point of view, represent a sector of development for cogeneration or trigeneration (production of heat, cooling and electricity). However, in the current conditions this does not represent an economically very attractive solution and should remain marginal in France.

In order to make an initial estimation of the technical potential of trigeneration by 2020, we have first estimated the total requirement for cooling in 2020. This requirement will be close to 77 TWh.

The corresponding technical potential of trigeneration will be around 1 GWth [18]:

		2020
Electricity	Installed power	– *
	Production	0.97 TWh e
Cooling	Installed power	0.94 GWh th
	Production	1 TWh th
Fuel	Production of cooling and electricity together	2.7 TWh

*To the extent that cooling should almost exclusively come as a complement to the production of heat through trigeneration, this does not change the technical potential of cogeneration previously calculated from the point of view of installed electrical capacity

Table 27 – 2020 technical trigeneration potential in cooling networks

[18] The hypotheses made are recapitulated in Annex 14 of this report.

This technology, which remains expensive compared to cooling units, will probably not develop much in France. Moreover, given the already significant cost of biomass cogeneration, and the associated significant technological constraints, trigeneration should be almost exclusively using natural gas, via gas engines and turbines. To the extent that economic conditions are relatively unfavourable, we have estimated that around 5% of the technical potential should be achieved by 2020, being an additional thermal capacity of around 50 GWth.

IV. MAIN DEVELOPMENT BRAKES AND LEVERS

As was made apparent in Chapter II, the technical potential should not be achieved by 2020, with output changing but not progressing overall (holding at around 20% of the technical potential, even though some sectors progress, such as residential and those industries controlling their fuel sources).

This can be explained by several causes

- Time parameter: the development of new specific sectors such as biomass cogeneration or micro-cogeneration takes time; therefore for these sectors, start-up is progressive over the period 2010-2020 to arrive at maturity in the period 2020-2030;
- Constraints linked to the investment in means of electricity production (insourced or outsourced): operational and financial constraints which mean that the technical choice is not a choice which is naturally "adapted" for the heat consumer;
- Brakes on development: linked to the current technological, economic and regulatory conditions, they prevent the full exploitation of some potentials achievable over the period 2010-2020. It is these brakes that we will analyse in this chapter, together with a list of measures which may remove all or part of these brakes and thus enable the cogeneration output to progress significantly by 2020.

1. Brakes for four cogeneration potentials

The analysis in the previous chapter (Economic potential) of alternatives for the heat consumer lead us to consider four potentials as being "braked" over the period 2010-2020:

- The potential for cogeneration from biomass: The economic potential in 2020 has been estimated at around 1 GW electricity. A more significant share of biomass in the fuel mix would enable greater primary energy and CO_2 emission savings.
- The potential for gas cogeneration on the market: a certain number of cogeneration facilities leaving the purchasing tariff will not go onto the market. For these facilities, operational constraints do not allow the market price for electricity to cover the extra operational costs linked to cogeneration, and will lead to the erosion of the gas cogeneration output.
- The potential for the renovation of gas cogeneration facilities: financially attractive on equivalent conditions, renovation will however not be chosen by all facilities, in particular due to operational constraints and to the risk involved in the heat source and the price of CO_2, which will also contribute to the erosion of the gas cogeneration output.
- The potential for micro-cogeneration: the current economic conditions do not allow the development of gas micro-cogeneration in existing constructions (and even less for biomass micro-cogeneration). This significant share of the technical potential may be exploited, even partially, through specific measures.

2. Development brakes and levers for each potential

For each potential, we have listed the principal brakes on the full realisation of the potential; these are brakes which may have been mentioned during interviews with stakeholders in the cogeneration sector.

To remove these brakes, we have next identified some action levers which may enable greater development of cogeneration than the economic potential calculated above.

This list of levers is not intended to be exhaustive. Moreover, at this stage these levers are only indications for action and should be the subject of a more profound analysis to validate their relevance.

a) Biomass cogeneration

The following brakes on the development of biomass cogeneration have been identified:

- Lack of structure of the forest biomass market: the dendroenergy offer is not sufficiently transparent, the pricing signal is not sufficiently clear, the market lacks liquidity and long-term supply contracts are rare. In consequence, heat consumers not having favoured access to the forest resource have difficulty in securing their supply.
- Strong uncertainty about the price of the biomass market: while price uncertainty is integral to all fuels, the lack of connection of the forest biomass price to energy prices (and in particular that of electricity), unlike that of gas, limits the possibilities of coverage and constitutes a risk to the profitability of biomass cogeneration.
- Requirement for improved productivity of the forest biomass sector: due in particular to the very divided structure of forest ownership in France, together with the recent rise of the dendroenergy sector, the exploitation of forest biomass is still very little mechanised: productivity gains would enable control of forest biomass prices in a context of tension over demand. This evolution towards greater productivity may today find itself in conflict with other uses for forest, in particular in terms of cultural and biodiversity value.
- Technology which is not yet mature: while biomass boilers today are accepted processes, biomass cogeneration facilities are still new to the market and the technology must still develop in terms of reliability and operating costs. The "unproven" character of this technology has a cost in terms of project finance.
- Atmospheric pollution: particulate emissions

To remove these brakes, several actions may be considered:

- Put in place a biomass price observatory: such an observatory would enable the emergence of average prices by forest basin; prices which could serve as a reference for heat consumers. This would have the advantage of highlighting the tension in terms of offer/demand balance, together with the differences in production costs across the national territory.

- Support productivity gains in the forest biomass sector: as plans for the mobilisation of biomass for energy use would create tension in the market, it would be necessary to encourage productivity gains to avoid too large an increase in the price of forest biomass. To achieve this, aid could be provided for investment in forestry exploitations in order to promote these productivity gains, while at the same time respecting other forest uses.
- Require the use of efficient smoke dust removal systems

b) Placing gas cogeneration on the market

The following brakes on the development of gas cogeneration on the electricity market have been identified:

- Lack of expertise on the electricity market: cogenerators, with the exception of the large outsourced facilities of specialist managers, do not possess the experience to control the operation of the electricity market and the associated risks. This may constitute a brake preventing facilities from going onto the market.
- Limitation of competitiveness on the electricity market: the operational constraints of coupling with the heat requirement result in lower flexibility in the facility than in its competitors on the free electricity market (at the forefront of which are the combined cycle gas turbines). This limited flexibility, together with the higher operating costs, limit the profitability of cogeneration facilities compared to their competitors.

To promote the development of cogeneration on the market, and in particular to increase the rate of use of facilities having decided to operate on the market, several actions may be considered:

- Promote the development of the aggregation offer: heat consumers not wishing to, or unable to, outsource electricity market management skills should be able to turn to an intermediary who can manage for them the placing on the market of the electricity produced.
- Remunerate the electrical capacities of cogeneration provided for by the NOME law: the capacity market aspect of the NOME law will enable the remuneration of installed electrical capacities.

c) Renovation of existing gas cogeneration facilities

The following brakes on the development of the renovation of gas cogeneration have been identified:

- CO_2 quota risk: from 2013, the CO_2 quotas for facilities subject to the ETS will be put up for auction. Today the feed-in tariffs do not take into account this extra cost which will materialise for facilities whose total power is greater than 20 MWth.
- Connection constraints for gas engines > 5 MWe: in 2010 the regulations have tightened the conditions for connection to the network (STEEGBH recommendations) in order to guarantee the

security of the network. While these conditions are achievable by gas turbine technologies, current gas engine technologies do not appear to be able to meet these conditions.

There is no clear economic profitability for gas cogeneration facilities: in the context of the targets for the reduction of greenhouse gas emissions and for the development of renewable energies, priority for the use of public resources will be granted to the development of biomass cogeneration.

d) Development of micro-cogeneration

The following brakes on the development of the renovation of gas cogeneration have been identified:

- Cost of technology still too high: in terms of operating costs, Stirling micro-cogeneration will be more expensive than the 'Condensing boiler + CESI' and 'Low temperature heat pump' solutions by around € 60 per year and € 120 per year respectively, which significantly limits its penetration.
- Weak support mechanism in existing constructions: micro-cogeneration technology is in competition with other technologies which have already penetrated the market such as heat pumps and solar thermal, which also have the advantage of being subsidised (in particular via the tax credit). For micro-cogeneration, the obligation to purchase for electricity currently produced set at 8 euro cents/kWh is not a sufficient incentive. Finally, the existing ESC forms (BAR-TH 35, BAT-TH-23, BAT-TH-28 GT) and those being prepared for the 7th order ('micro-cogeneration boiler') cannot alone compensate for the extra cost of micro-cogeneration.
- Connection constraints: the procedure for commissioning a connection to the network for a micro-cogenerator in the case of the sale of a surplus has a duration of around 6 months and 3 months. These installation procedures are restrictive and may be prohibitive for project owners and project managers who may find these procedures too restrictive to decide to invest. A simplification and acceleration of the process would contribute to the development of micro-cogeneration in France. The feed-in arrangements currently give rise to connection fees of between € 200 and € 400 including tax, and annual fees of € 57 including tax invoiced by ErDF (the French electricity distribution network).

To promote the development of micro-cogeneration, particularly in existing buildings, the following actions may be considered:

- Introduction of a feed-in tariff specific to micro-cogeneration: a feed-in tariff adapted to the current economic conditions of cogeneration may be one solution to promote the installation of output in a more substantial manner. Degression of this purchasing tariff according to the expected reduction in investment costs should be considered.
- Other incentives: different investment aid schemes may be considered in order to improve the time-scale for return on investment: in addition to the benefits of the tax credit attributed to the most efficient technologies already mentioned, micro-cogeneration may also be eligible for the "zero rate eco-loan" system for operations of energy renovation.

- Development of intelligent meter systems: in order to simplify the procedures for metering and invoicing of electricity produced and sold to the network, the expected development of intelligent meters should enable the removal of current brakes.

There is therefore strong potential for the development of micro-cogeneration in the context of the implementation of intelligent networks ("smart grids"). Research and development actions should still be carried out to produce efficient technologies with prospects for medium term profitability.

CONCLUSION

The energy structure and choices of France have not so far required significant recourse to cogeneration. If we consider total electricity production, cogeneration remains underdeveloped in France compared to our European neighbours, which is explained by the French choice for the development of nuclear energy enabling the production of low price electricity with low carbon dioxide emissions. The electricity production of cogeneration facilities does, however, represent a significant share of conventional French thermal electricity production (thermal power stations), of around 40%.

France considers that the combined production of heat and electricity constitutes an efficient means of rationally using energy when there exist real heat requirements, particularly in industry and urban heating. France has always demonstrated its attachment to the definition of high efficiency cogeneration based on primary energy savings and to the necessity of achieving a high degree of European harmonisation for definitions and calculation methods. However, France estimates that it is not opportune, given the diversity of the energy systems in the countries of the European Union, to move towards the systematic homogenisation of cogeneration development in each of the Member States.

French cogeneration output is at a turning point in its development: after the decade 2000-2010 which has seen the output of plants increase very rapidly (from 1 to 6 GWe) thanks to a policy of support for gas cogeneration, the reorientation of this support policy, in particular towards biomass cogeneration, should profoundly modify the conditions for cogeneration in France and transform the existing sector.

In current conditions, and assuming a certain number of economic hypotheses, while the cogeneration output, currently primarily supplied by gas, should partially convert to biomass, it does not seem inclined to increase its overall capacity for electricity production, which will probably regress by 2020 by 5 to 15%, depending on the hypotheses made.

While the calculation of the technical potential demonstrates the theoretical possibility of covering a large part of the heat requirements of all segments considered with an installed output of around 30 GWe, the maturity of the technologies, economic conditions and the orientation of support policies result in a contained and progressive rise in biomass cogeneration, an increase which does not completely compensate for the exit from the sector of some of the gas cogeneration facilities.

It should be noted that the realisation of this economic potential will enable France by 2020 to annually save around 4.5 million tonnes of CO_2 and 2.75 million tonnes of petrol equivalent of primary energy, while at the same time mobilising renewable energies for the production of electricity to a figure of 1 GW, for a support policy cost (SCOPE) of around 1.1 billion euros.

On the micro-economic level, cogeneration facilities without support arrangements (and which must purchase their fuel) present the French heat consumer with a competitiveness deficit compared to separate production of heat and purchase of electricity from the network, due to the low cost of electricity, significant over-investment and resulting flexibility constraints for the heat consumer.

For France, the challenge of the years to come is to permit the rise of biomass cogeneration: these facilities have the advantage of contributing in three ways to the "3x20" policy of the energy-climate package. The challenge here is to release investments in new capacities by providing visibility to revenues and minimising the risk linked to the biomass supply sector.

The identified current brakes prevent a complete response to these challenges. The implementation of a certain number of action levers may contribute to removing these brakes and thereby enable the French cogeneration output to reach a new stage and to contribute to further increasing primary energy gains while meeting the targets for the reduction of greenhouse gas emissions and for the development of renewable energies.

Glossary

ADEME: Agence de l'environnement et de la maîtrise de l'énergie (French Environment and Energy Management Agency); http://www.ademe.fr

AMORCE: Association nationale des collectivités, des associations et des entreprises pour la gestion des déchets, de l'énergie et des réseaux de chaleur (French national association of local and regional authorities, associations and businesses for the management of waste, energy and heating networks); http://www.amorce.asso.fr

ATEE: Association technique énergie environnement (French Energy Environment Technical Association); http://www.atee.fr/

CCGT: Combined Cycle Gas Turbine

CESI: Chauffe Eau Solaire Individuel (Individual solar water heater)

CFT: Call for Tenders

CIBE: Comité Interprofessionnel du Bois-Energie (French Dendroenergy Trade Association); http://www.cibe.fr/

Clean spark spread: gross margin realised by an electricity producer from a gas power station, after the cost of the CO_2 has been deducted; spark spread reduced by the cost of CO_2 associated with the production of the electricity produced.

DHW: Domestic Hot Water

EL: Engineered Landfill site

ERC: Energy Regulation Commission; http://www.cre.fr/

H/E: heat/electricity ratio: thermal cogeneration power (MWth)/electrical cogeneration power (MWe), or: production of cogenerated heat (MWh th)/production of cogenerated electricity (MWh e)

HN: Heating Network

MCHP: Micro Combined Heat and Power, or micro-cogeneration

OP: Obligation to Purchase

SCOPE: CSPE - Contribution au service public de l'électricité (Contribution to the Public Electricity Service)

SOeS: Service de l'Observation et des Statistiques (French Observation and Statistics Office); http://www.statistiques.equipement.gouv.fr/

Spark spread: gross margin realised by an electricity producer from a gas power station; the difference between the price the electricity is sold for on the market and the cost of the fuel to produce this quantity of electricity.

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Annex 1 – Detailed hypotheses concerning the evaluation of thermal requirements in 2008

i. Residential (excluding heating networks)

The evaluation of heat requirements for the residential sector is based on the consumptions observed for that sector. A hypothesis regarding average yields for heat production systems enables the calculation of heat requirements for the sector.

Energy consumptions by the residential sector for heating and domestic hot water (DHW) production excluding heating networks have been deduced from the ADEME study Les chiffres clés du bâtiment (Building sector key figures) [7] and from the SNCU enquête nationale de branche sur les réseaux de chaleur et de froid (National industry enquiry on heating and cooling networks) [8] in order to deduce the consumption linked to heating networks[19]. The calculation of average yields for heating and DHW production systems was in addition based on a study by VNK [9]. It produces the following values:

System	Average yield
Heating (excluding distribution losses)	71.5%
Production of DHW (excluding distribution and storage losses)	89.8%

Table 28 – Hypotheses regarding average yields for heating and DHW production systems in the residential sector in 2008 (sources: ADEME [7] and VNK [9])

The heat requirements of the sector were obtained by dividing the consumption of the sector by these average yields.

ii. Tertiary (excluding heating networks)

The calculation of heat requirements for the tertiary sector excluding heating networks was carried out in the same manner as for the residential sector. Consumptions are based on data from the ADEME [7] and the SNCU [8]. The VNK study [9] enables the obtention of average yields for heating and DHW production systems:

System	Average yield
Heating (excluding distribution losses)	75.6%
Production of DHW (excluding distribution and storage losses)	89.8%

Table 29 – Hypotheses regarding average yields for heating and DHW production systems in the tertiary sector in 2008 (sources: ADEME [7] and VNK [9])

iii. Heating Networks

The heat requirements of customers connected to heating networks were assumed to be equal to deliveries of heat by the networks. This data results from the SNCU enquête nationale de branche sur les réseaux de chaleur et de froid (National industry enquiry on heating and cooling networks) [8]. This describes the deliveries of heat for the tertiary sector (health, education, other), residential, industrial and other sectors. To distribute these deliveries by the sectors adopted in the current study, the following hypotheses have been made:

- Residential: all deliveries of heat from networks are made in the sub-sector of multi-occupancy housing only
- Tertiary: deliveries to the different 'Other' tertiary sub-sectors were divided on a prorata basis according to consumption
- Industry: deliveries to the different industrial sub-sectors were divided on a prorata basis according to consumption; only refineries have been assumed not to be connected to heating networks

iv. Industry (excluding heating networks)

The heat requirements of industry are a result of the overlapping of various sources and interviews with trades unions. The heat requirements satisfied by the networks have been removed, as for the other sectors.

v. Other

The heat requirements of other sectors (greenhouses and pig and poultry breeding) have been calculated on the basis of the data from CLIP Cahier no. 15 [10]. The heat requirements satisfied by the networks for the 'Other' sector of the SNCU inquiry [8] were also removed here.

[19] During the execution of the study, the latest available data from the ADEME study was that relating to 2007. The hypothesis was made that consumption would remain stable in 2008, the increase in output being compensated for by the reduction in unit consumption.

Annex 2 – Hypotheses concerning the estimation of thermal requirements in 2020

i. Residential (excluding heating networks)

The development of heat requirements for the entire residential sector have been based on the hypotheses adopted in the 2009 heat PPI:

	2005	2010	2020	2005-2010	2010-2020
Heating requirement (Mtoe)	31.9	32.74	22.67	+2.6%	-30.8%
Total DHW requirement (Mtoe)*	4.91	5.32	5.97	+8.3%	+12.4%
DHW requirement (L/pers./yr)	1.23	1.3	1.4	+5.7%	+7.7%
Population (million)	60.8	62.3	65	+2.5%	+4.3%
Total (Mtoe)	36.8	38.1	28.6	+3.4%	-24.7%

Table 30 – Hypotheses regarding the development of heat requirements in the residential sector
(* including requirements covered by solar thermal) (source: Heat PPI [11])

The distinction between individual and collective has been made according to the hypotheses made by the PPI:

Existing stock (million main res.)	2005	2010 *	2020	2005-2010	2010-2020
Apartments	11	11.6	12.8	+5.2%	+10.6%
Single family houses	14.4	15.0	16.6	+4.0%	+10.9%
Total	25.4	26.5	29.4	+4.5%	+10.8%

Table 31 – Hypotheses regarding the development of the multi-occupancy and individual housing stock
(* 2010: linear interpolation according to PPI) (source: Heat PPI [11])

ii. Tertiary (excluding heating networks)

The hypothesis regarding the development of heat requirements in the tertiary sector also results from the 2009 Heat PPI [11]:

Mtoe	2005	2010	2020	2005-2010	2010-2020
Heat requirement	14.9	15.48	7.27	+3.9%	-53.0%

Table 32 – Hypotheses regarding the development of heat requirements in the tertiary sector
(source: Heat PPI [11])

It has been considered that the development in needs will be identical in all tertiary sub-sectors.

iii. Heating Networks

For the calculation of heat requirements associated with heating networks, the significant growth of the networks in terms of connected equivalent housing units as presented in the PPI has been corrected by the reduction in unit consumption.

In the residential sector, the development of unit consumption considered results directly from the PPI. Combined with the development of the number of equivalent housing units connected to the networks, this enables the calculation of the development of heat consumption for housing connected to heating networks:

	2005	2010 *	2020	2005-2010	2010-2020
Million equivalent housing units	1	1.2	2.5	+21.4%	+105.9%
Unit consumption devel. (index)	1	1	0.69	-0.1%	-31%
Total HN consumption devel. (index)	1	1.21	1.73	+21.4%	+42.4%

Table 33 – Hypotheses regarding the development of heat consumption linked to heating networks in the residential sector (* 2010: linear interpolation according to PPI) (source: Heat PPI [11])

The heat requirements of the residential sector have been assumed to follow the same development.

Regarding tertiary buildings, the overall development of consumption in the sector has been based on the calculations of the Heat PPI. The average growth of the tertiary stock has been considered as being of +1.7%/year until 2010, then +1.6%/year from 2010 to 2020 (according to [12]). These hypotheses enable the evaluation of the development of heat consumption in tertiary buildings connected to heating networks:

	2005	2010 *	2020	2005-2010	2010-2020
Million equivalent housing units	1	1	1.3	0.0%	+30.0%
Unit consumption devel. (index)	1	0.96	0.55	-4.1%	-43.1%
Total HN consumption devel. (index)	1	0.96	0.71	-4.1%	-26.1%

Table 34 – Hypotheses regarding the development of heat consumption linked to heating networks in the tertiary sector (* 2010: linear interpolation according to PPI) (source: Heat PPI [11] and SES [12])

The heat requirements of the tertiary sector have been assumed to follow the same development.

The distribution of heating networks within different sectors has been assumed to be constant. In addition, heat requirements for the 'Industry' and 'Other' sectors have been considered as constant for the period 2008-2020.

iv. Industry (excluding heating networks)

The hypotheses of growth in heat requirements in industry as considered in the Heat PPI appeared too optimistic to those stakeholders in the sector encountered during the current study. A hypothesis of stabilisation of heat requirements between 2008 and 2020 appeared to be more realistic. It is therefore this hypothesis which has been adopted.

v. Other

The hypothesis has been made of stabilisation of requirements in the 'Other' sector.

Annex 3 – Heat requirements of different sectors

Dimensioning cogeneration for residential and tertiary sectors (source: [15], [22]):

Sector	Cogeneration dimensioning		Particularity
	% max. power	% heat requirement	
Offices, education	20%	43%	Regular occupation + daily restart 5 days a week
Shops	21%	41%	Variable occupation 6 days a week
Sport	44%	47%	Requirement 7 days a week and specific usage (DHW + swimming pool)
Health	24%	45%	Continuous heating and DHW requirements 7 days a week
Housing	30%	43%	Partial slow-down during the day
Heating networks	45%	45%	Proliferation effect

Dimensioning cogeneration for the 'Industry' and 'Other' sectors (sources: interview with UNIDEN and report on the national potential for cogeneration in Spain [18]):

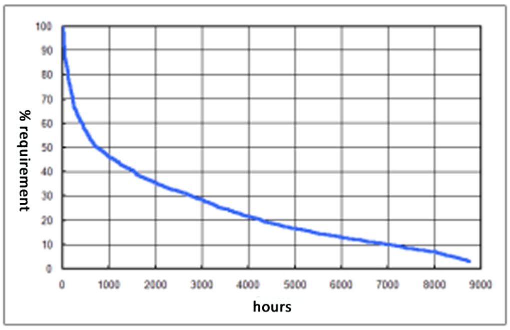
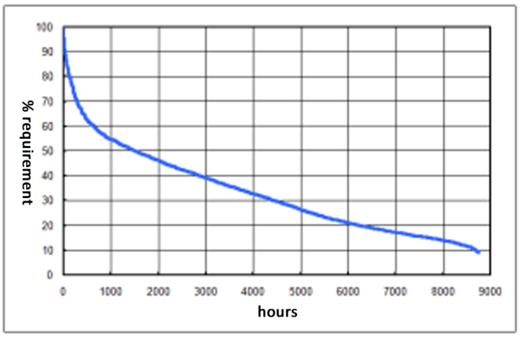
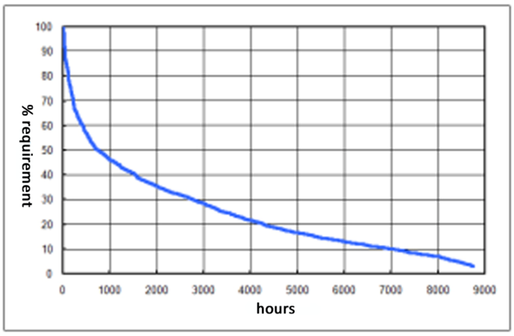
Sector	Cogeneration dimensioning	Particularity
Agri-foodstuffs (inc. sugar refineries)	70%	5 days a week with nocturnal reduction
Chemicals (inc. elastomers)	75%	Minor reduction in activity at weekends
Paper/cardboard	96%	Constant operation all year (without major shutdown)
Refineries	96%	
Automobile industry	71%	Constant requirements outside annual shutdown
Greenhouses	60%	Climatic effect
Others	76%	Average across different sectors

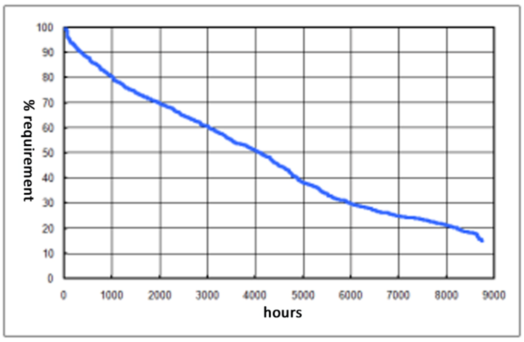
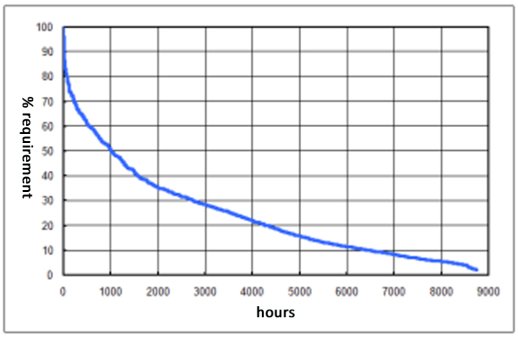
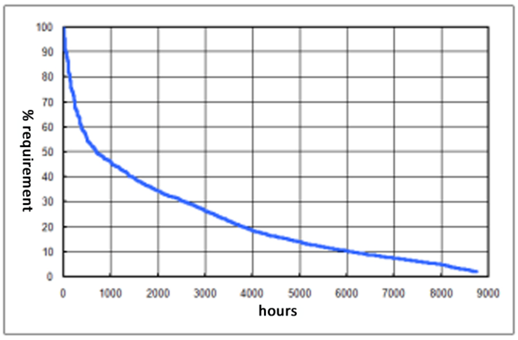
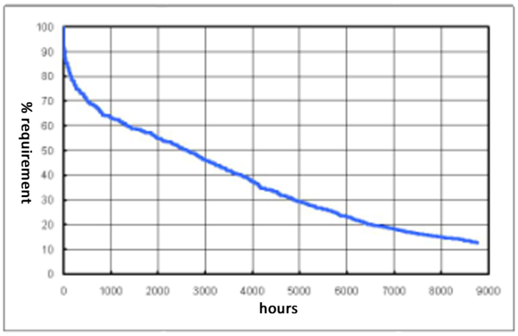
Annex 4 – Hypotheses concerning the estimation of the technical potential of cogeneration

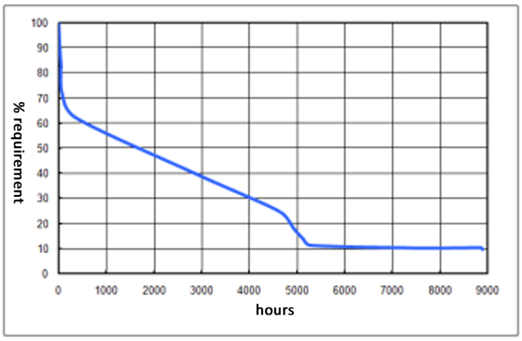
a) Technical potential by sector

i. Load duration curves of heat requirement

In order to establish the cogenerable share of the requirement by sector, the following load duration curves were used:

Sector	Profile	Load duration curve
Residential		
Collective	Daytime activity 7 days a week Ref. [15]	
Tertiary (exc. HN)		
Health	Continuous activity 7 days a week Ref. [15]	
HORECA (cafés, hotels, restaurants)	Continuous activity 7 days a week Ref. [15]	
Co-housing	Daytime activity 7 days a week Ref. [15]	

Sport-leisure	Daytime activity 7 days a week Ref. [15]	
Shops	Daytime activity 6 days a week Ref. [15]	
Education-Research	Daytime activity 5 days a week Ref. [15]	
Offices	Daytime activity 5 days a week Ref. [15]	
Transport (stations, airports)	Ref. [16]	

<table>
<tr><td>Heating Networks</td><td>Ref. [17]</td><td>
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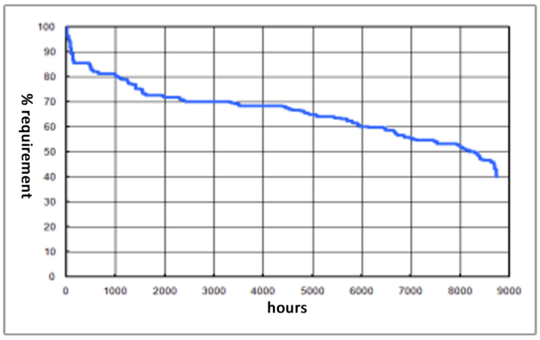
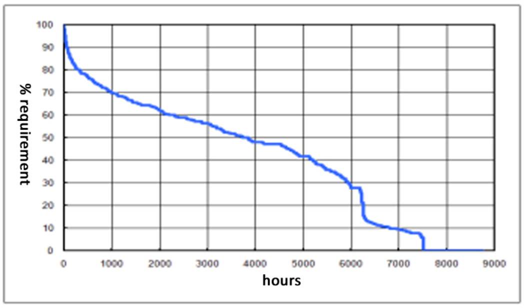
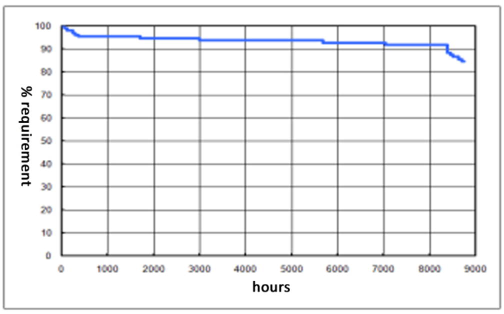
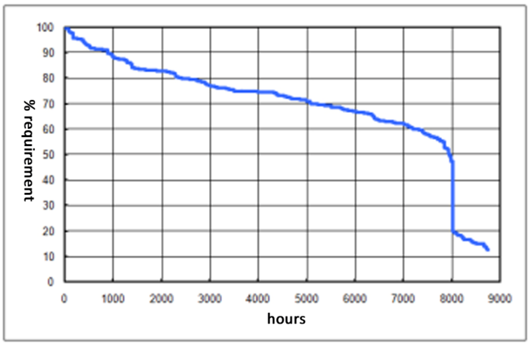
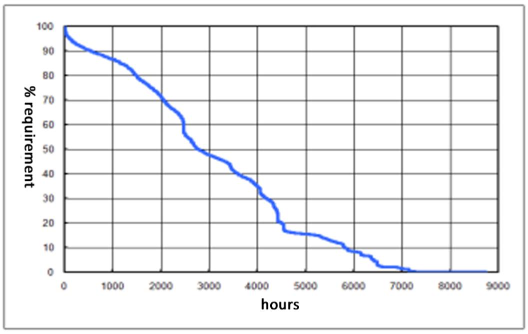
<tr><td colspan="3">Industries</td></tr>
<tr><td>Chemicals</td><td rowspan="2">Ref. [18]
Modifications made following interview with UNIDEN</td><td>
</td></tr>
<tr><td>Agri-foodstuffs</td><td>
</td></tr>
<tr><td>Paper/cardboard</td><td rowspan="2">Ref. [18]
Modifications made following interview with UNIDEN</td><td rowspan="2">
</td></tr>
<tr><td>Refineries</td></tr>
</table>

Automobile industries	Aggregation of various sources	
Other (exc. HN)		
Greenhouses	Aggregation of various sources	

ii. Complementary hypotheses

	Cogenerable share of heat requirement	Operating hours	Average H/E
	%	hrs/year	-
Residential (exc. HN)	43%	3 373	2.13
Collective	43%	3 373	0.96
Individual	43%	3 373	3.32
Tertiary (exc. HN)	42%	3 475	1.11
Health	45%	3 475	1.06
Education-Research	39%	3 475	1.06
Co-housing	43%	3 475	0.82
Sport-leisure	47%	3 475	1.06
Shops	41%	3 475	1.19
Cafés, hotels, restaurants	45%	3 475	1.19
Offices	39%	3 475	1.19
Transport (stations, airports)	46%	3 475	1.25
Heating Networks	45%	3 373	1.44
Industry (exc. HN)	80%	3 272	3.04
Agri-food (inc. sugar refineries)	70%	3 127	2.84
Chemicals (inc. elastomers)	75%	3 127	3.71
Paper/cardboard	96%	3 127	3.71
Refineries	96%	4 391	2.32
Automobile equipment manufacturers	71%	3 127	2.69
Other (aeronautical, electronics, etc.)	77%	3 127	2.84
Other (exc. HN)	57%	3 814	1.00
of which greenhouses	60%	3 814	1.00
TOTAL	54%	3 354	2.11

Table 35 – Hypotheses relating to the evaluation of the technical potential: cogenerable share of heat requirement, operating hours and average H/E by activity segment and sub-segment for 2020

b) Technical potential by technology

	ST	ICE	GT	CCGT	PaCO	µ T	µ Stirling	µ PaCO	µ ICE	TOTAL
Residential (exc. HN)										-
Collective	0%	82%	4%	0%	13%	0%	0%	0%	0%	100%
Individual	0%	0%	0%	0%	0%	0%	70%	20%	10%	100%
Tertiary (exc. HN)										-
Health	0%	78%	16%	0%	5%	0%	0%	0%	0%	100%
Education-Research	0%	78%	16%	0%	5%	0%	0%	0%	0%	100%
Co-housing	0%	45%	9%	0%	45%	1%	0%	0%	0%	100%
Sport-leisure	0%	78%	16%	0%	5%	0%	0%	0%	0%	100%
Shops	0%	64%	6%	0%	18%	0%	7%	2%	1%	100%
Cafés, hotels, restaurants	0%	64%	6%	0%	18%	0%	7%	2%	1%	100%
Offices	0%	64%	6%	0%	18%	0%	7%	2%	1%	100%
Transport (stations, airports)	0%	42%	50%	8%	0%	0%	0%	0%	0%	100%
Heating Networks	7%	33%	26%	34%	0%	0%	0%	0%	0%	100%
Industry (exc. HN)										-
Agri-food (inc. sugar refineries)	39%	33%	28%	0%	0%	0%	0%	0%	0%	100%
Chemicals (inc. elastomers)	58%	0%	33%	9%	0%	0%	0%	0%	0%	100%
Paper/cardboard	58%	0%	33%	9%	0%	0%	0%	0%	0%	100%
Refineries	29%	0%	10%	61%	0%	0%	0%	0%	0%	100%
Automobile equipment manufacturers	37%	6%	14%	43%	0%	0%	0%	0%	0%	100%
Other (aeronautical, electronics, etc.)	39%	33%	28%	0%	0%	0%	0%	0%	0%	100%
Other (exc. HN)										-
of which greenhouses	0%	91%	5%	0%	5%	0%	0%	0%	0%	100%

Table 36 – Hypotheses relating to the distribution of technologies by sector

H/E	ST	ICE	GT	CCGT	PaCO	µ T	µ Stirling	µ PaCO	µ ICE
2010	5.4	1	1.5	1		1.8	6		2.4
2015	5.4	1	1.5	1	0.8	1.6	5	0.8	2.4
2020	5.4	1	1.5	1	0.5	1.6	4.25	0.5	2.4

Table 37 – Hypotheses relating to H/E ratios for each technology according to timeframe

ST: steam turbine
ICE: internal combustion engine
GT: gas turbine
CCGT: combined cycle gas turbine
PaCO: fuel cell

µ T: micro-turbine
µ Stirling: Stirling micro-engine
µ PaCO: micro-fuel cell
µ ICE: internal combustion engine

Steam turbine:

Main characteristics

- Production of hot water or steam
- Adapted to stable requirements
- Installed fleet (number of units): Industry (54%), Refineries (23%), UIOMs (23%)
- Very good overall yield and high H/E ratio

Technical data

Typical size (MW e)	H/E ratio	Overall yield	Electrical yield
2 - 20	4-20	70-90%	5-18%

Areas of application

- Large-scale industry
- UIOMs
- Heating networks

Operating diagram

Advantages

- Mature technology
- All types of fuel

Limitations

- Start-up time > 1 hr (adapted for continuous operation)
- Very noisy

Gas turbine

Main characteristics

- Production of hot water or steam
- Gaseous or liquid fuel only
- Very reliable technology
- Yield which decreases rapidly with load

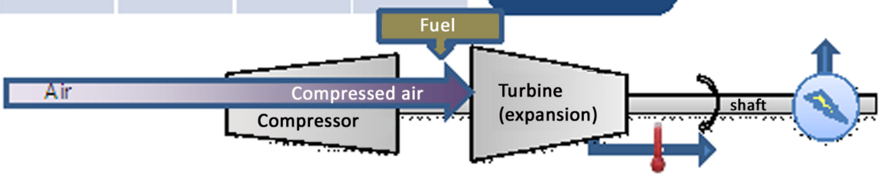
Technical data

Typical size (MW e)	H/E ratio	Overall yield	Electrical yield
14	0.5-2	70-80%	20-35%

Areas of application

- Large-scale industry
- Heating networks

Operating diagram



Advantages

- Mature technology
- Rapid start-up (3-5 mins)
- Low CO_2 emissions

Limitations

- Poor yield on partial load
- Low electrical yield for low powers
- Noisy

Combined cycle

Main characteristics

- Production of hot water or steam
- Significantly improved electric yield compared to gas turbine
- Improved H/E ratio

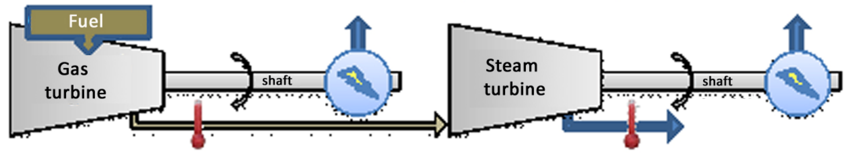
Technical data

Typical size (MW e)	H/E ratio	Overall yield	Electrical yield
10	0.3 -1	70-80%	40-60%

Areas of application

- Large-scale industry
- Heating networks

Operating diagram



Advantages

- Mature technology

Limitations

- Very noisy

Internal combustion engine

Main characteristics

- Production of hot water only
- Gaseous or liquid fuel only
- Good yields on partial load
- Residual heat difficult to recover

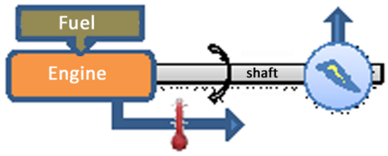
Technical data

Size (kW e)	H/E ratio	Overall yield	Electrical yield
0.005 - 50	0.5-2	65-80%	33-45%

Areas of application

- Residential
- Tertiary

Operating diagram



Advantages

- Mature technology
- Start-up in a few seconds (can act as back-up in the case of breakdown)

Limitations

- High maintenance costs
- Not suitable for the production of steam
- Limited life time (100 000 hrs)
- Very noisy

Fuel cell

Main characteristics

- Production of hot water or steam
- Market availability hypothesis: 2015
- Hydrogen not naturally available; generally produced by reforming hydrocarbons and in particular natural gas
- Low temperature (LT; 70 to 200°C) and high temperature technologies (HT; 650 to 1000°C)
- Good performance on partial load

Technical data

Typical size (kW e)	H/E ratio	Overall yield	Electrical yield
200 kW	0.5-1.2	80-90%	25-55%

Areas of application

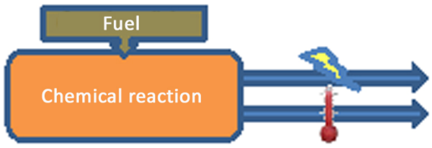
Low temperature:

- Residential
- Tertiary

High temperature

- all sectors

Operating diagram



Advantages

- Very low powers possible (single family home residential)
- Very little noise

Limitations

- Currently at demonstration stage
- Hydrogen availability

Annex 6 – Cogeneration capacity development model

a) Detailed economic hypotheses

Costs of investment and operation of reference technologies

Cogeneration is an alternative to the separate production of heat. In order to measure the economic attractiveness of resorting to cogeneration rather than to a boiler to meet a heat requirement, the simulations were carried out for the two cases.

The means of separate production of heat considered in this study are the gas boiler (generally used as reference for the production of heat) and the biomass boiler, benefiting from an environmental advantage compared to fossil energy solutions.

The costs considered for these boilers follow the curves below:

Investment costs

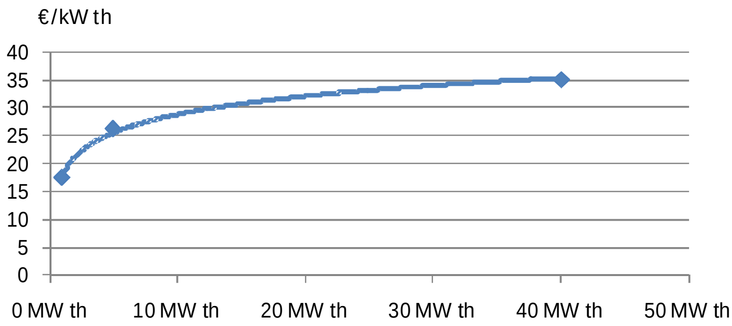


Figure 33 – Development of investment costs for a gas boiler according to power (source: ATEE)

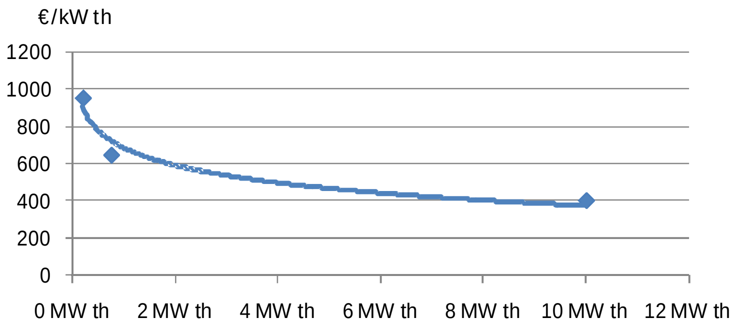


Figure 34 – Development of investment costs for a biomass boiler according to power (source: ADEME/Perdurance [21])

Operating costs

The operating costs considered in the study for the separate production of heat are:

- Gas boiler: 0.2 euro cents/kWh th (source: interviews)
- Biomass boiler: 0.9 euro cents/kWh th (source: interview with CIBE)

Cogeneration investment costs

For 2010 (unless otherwise stated), the investment costs adopted for newly installed cogeneration facilities follow the curves presented in the figures below, according to the power range and technology adopted.

Unless otherwise stated in the figures below, the levels of investment costs have been assumed to be constant over the period considered.

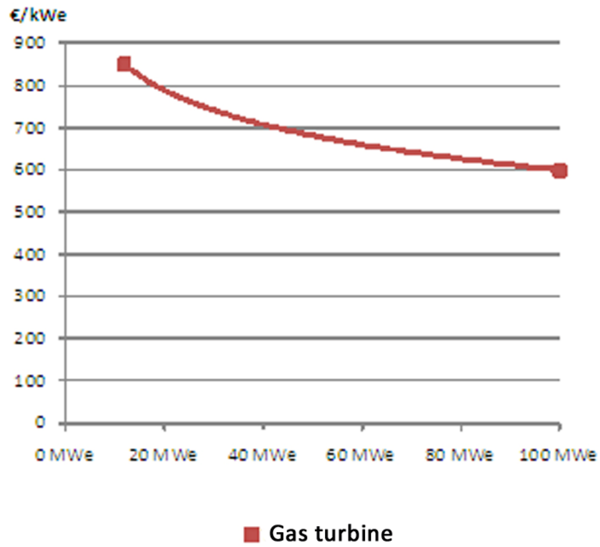


Figure 35 – Development of investment costs for large-scale cogeneration (> 12 MWe)
(sources: DGEC and interviews)

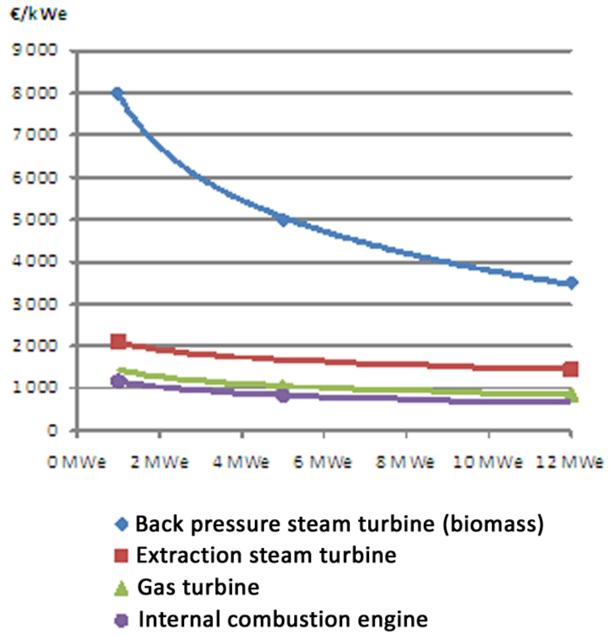


Figure 36 – Development of investment costs for medium-scale cogeneration (1 to 12 MWe) (sources: CIBE [19], IEPF Cogeneration trigeneration 2005, DGEC, ATEE)

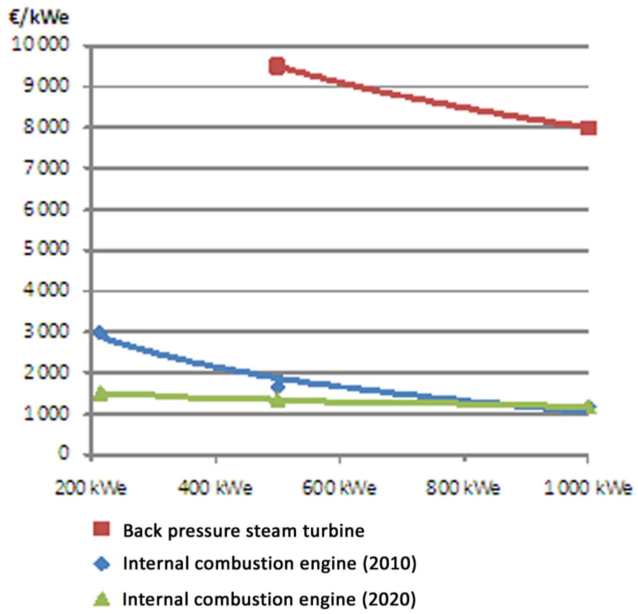


Figure 37 – Development of investment costs for small-scale cogeneration (215 to 1 000 kWe) (sources: DGEC, ATEE)

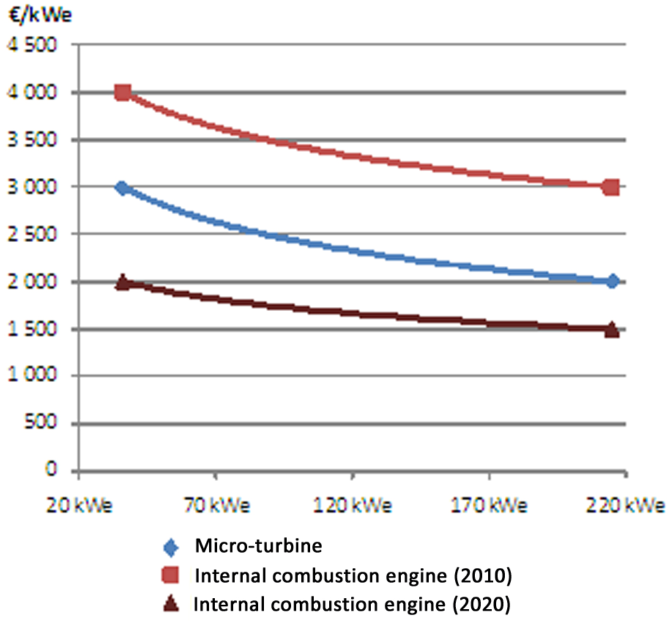


Figure 38 – Development of investment costs for mini-cogeneration (36 to 215 kWe) (sources: interviews)

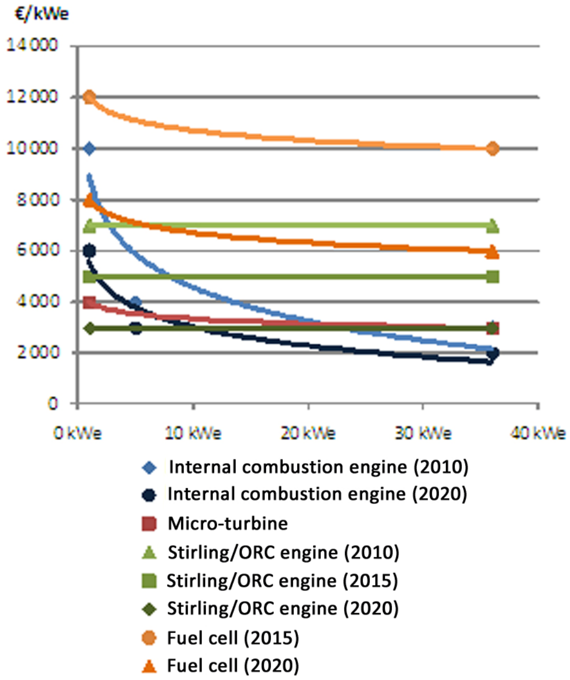


Figure 39 – Development of investment costs for micro-cogeneration (< 36 kWe) (sources: interviews)

Cost of renovation and overhaul

To be eligible for contract C01-R, a facility renovation with a minimum investment of € 350/kW installed[20] is required, this threshold being indexed annually. Following interviews carried out with the profession, it has been set for this study at € 380/kW. Cogeneration facilities coming to the end of the obligation to purchase contract must be reviewed in order to ensure maximal performance.

If the cogeneration facility is not eligible for contract C01-R and/or if it decides to go onto the market, major maintenance (or overhaul) is still necessary. This operation is essential every ten to fifteen years for the correct operation of the facility. Interviews carried out with the profession have enabled us to set this cost at € 150/kW.

Cogeneration operating costs

For 2010 (unless otherwise stated), the operating costs adopted for cogeneration facilities follow the curves presented in the figures below, depending on the power range and technology adopted.

These costs have been assumed to increase by 2% per year.

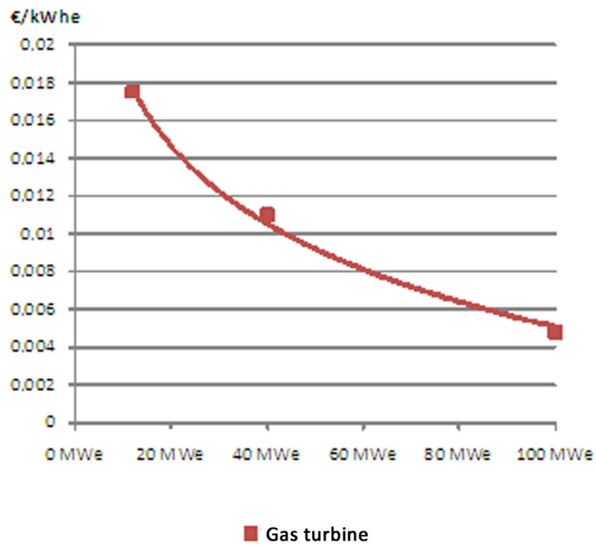


Figure 40 – Development of operating costs for large-scale cogeneration (> 12 MWe) (source: DGEC)

[20] Value for January 2007.

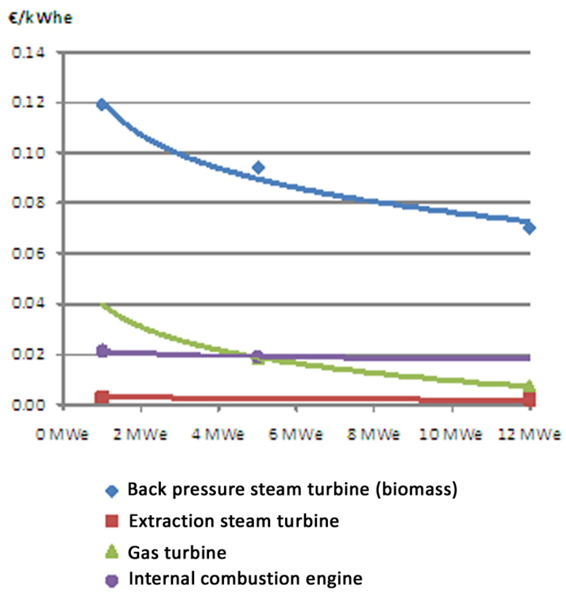


Figure 41 – Development of operating costs for medium-scale cogeneration (1 to 12 MWe)
(sources: CIBE [19], IEPF Cogeneration trigeneration 2005, DGEC, ATEE)

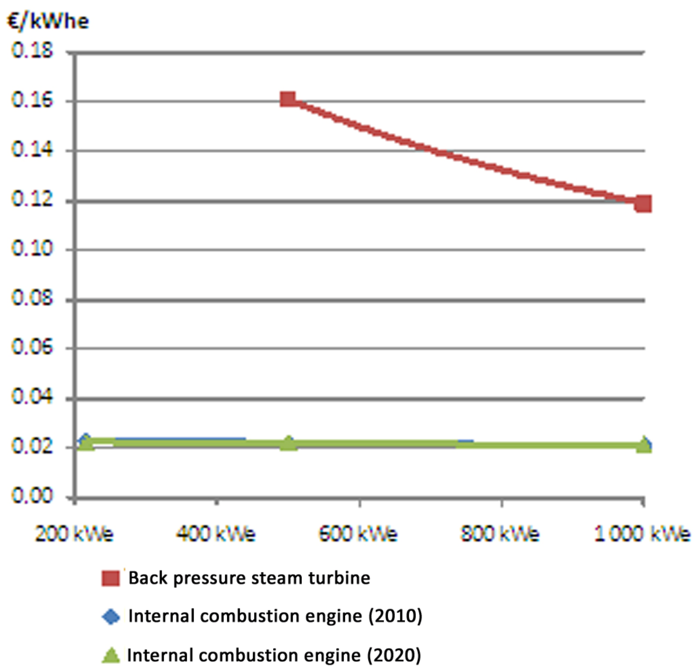


Figure 42 – Development of operating costs for small-scale cogeneration (215 to 1 000 kWe)
(sources: CIBE [19], ATEE, interviews)

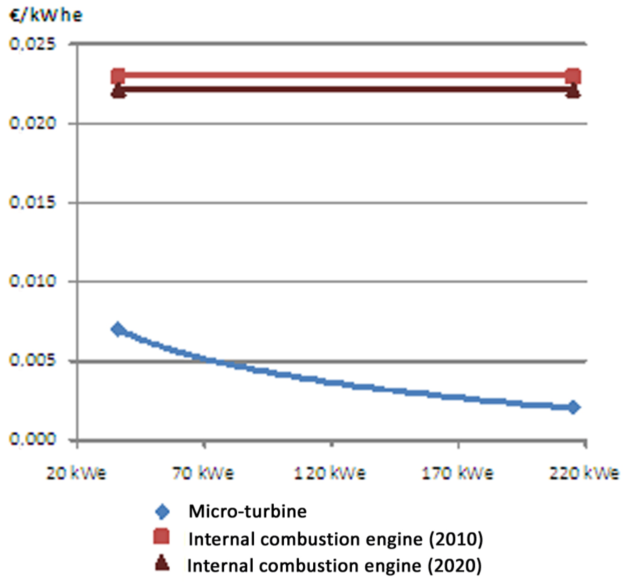


Figure 43 – Development of operating costs for mini-cogeneration (36 to 215 kWe) (sources: interviews)

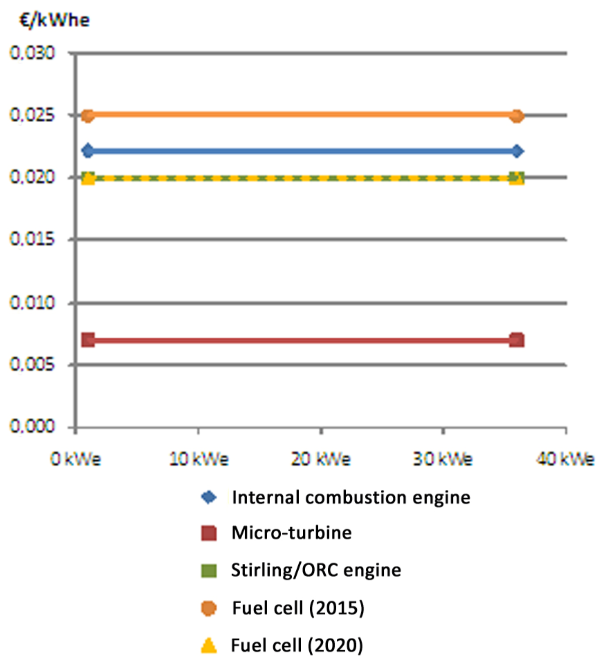


Figure 44 – Development of operating costs for micro-cogeneration (< 36 kWe) (sources: interviews)

Electricity sale tariff: hypotheses relating to the electricity market

In order to calculate the different levels of electricity price, different levels of clean spark spread have been set by hypothesis in the study and are assumed to remain constant over the period of time considered in the study:

Period	Clean spark spread (€/MWh)
Off peak summer	0
Off peak winter	5
Peak summer	20
Peak winter	25
Peak	60

Table 38 – Hypotheses regarding the levels of clean spark spread according to the period of electricity production

With a Zeebrugge gas price of € 22/MWh for 2010, a CO_2 price of € 15/tonne and the levels of clean spark spread previously seen (cf. Table 39), the resulting electricity prices considered in the study are as follows:

Period	Electricity price (€/MWh)
Off peak summer	45.4
Off peak winter	50.4
Peak summer	65.4
Peak winter	70.4
Peak	105.4

Table 39 – Hypotheses regarding electricity prices according to production periods for 2010

However, these price levels may not necessarily be directly achieved by a cogeneration facility. Depending on the technology, cogeneration facilities are more or less capable of regular stoppages and restarts. Depending on the flexibility of the facility, the average tariff achieved on the market varies: only a facility able to stop and restart several times per week will be able to achieve the higher market tariffs, while a facility which can only stop and restart once a week will achieve a lower average market price.

To model this difference, the study has considered two market prices according to the flexibility of the cogeneration facilities:

- One stoppage per week (cf. Figure 45)
- One stoppage per day (cf. Figure 46)

The former hypothesis of one stoppage per week which was finally adopted. This appeared to be more likely given the technologies modelled, and following interviews carried out with the profession.

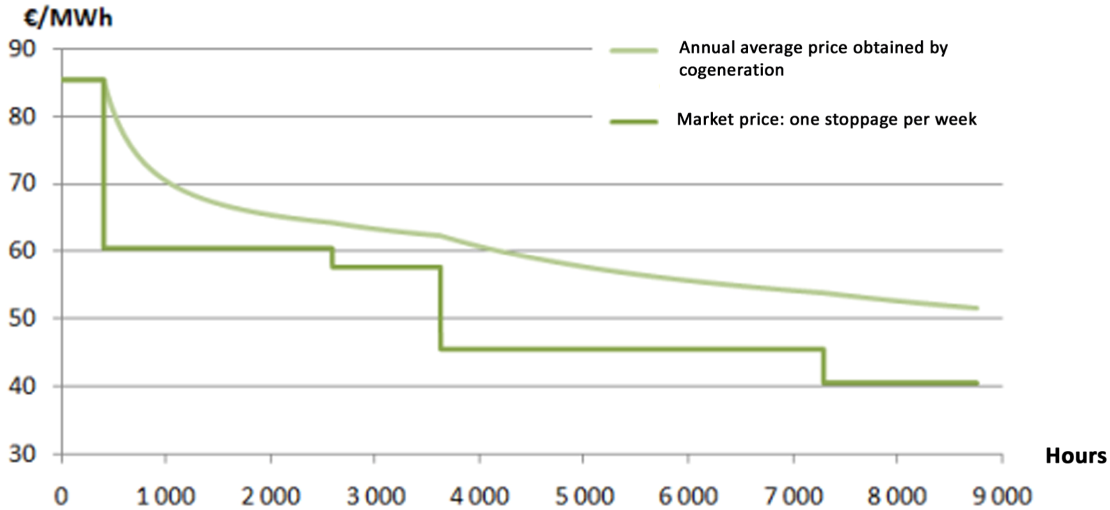


Figure 45 – Average price of electricity achieved on the market by a cogeneration facility with one stoppage per week, depending on the number of operating hours (hypothesis adopted for model)

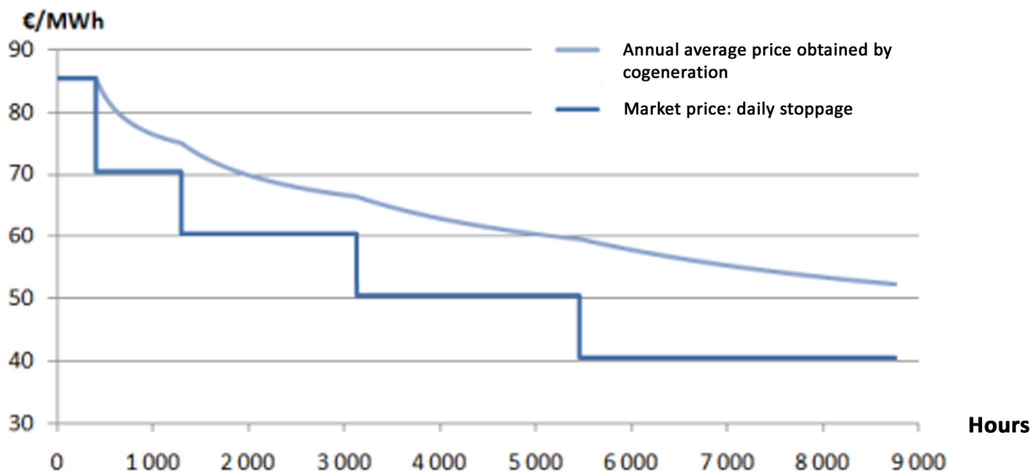


Figure 46 – Average price of electricity achieved on the market by a cogeneration facility with one stoppage per day, depending on the number of operating hours

b) Technical hypotheses: cogeneration yields

For the whole study, the average yields by cogeneration technology considered are as follows:

Technology		2010	2015	2020
Back pressure steam turbine (biomass)	Electric yield	14%	14%	14%
	Thermal yield	76%	76%	76%
	Overall yield	90%	90%	90%
	H/E	5.4	5.4	5.4
Extraction steam turbine	Electric yield	14%	14%	14%
	Thermal yield	76%	76%	76%
	Overall yield	90%	90%	90%
	H/E	5.4	5.4	5.4
Gas turbine	Electric yield	32%	32%	34%
	Thermal yield	48%	48%	51%
	Overall yield	80%	80%	85%
	H/E	1.5	1.5	1.5
Internal combustion engine	Electric yield	40%	40%	42.5%
	Thermal yield	40%	40%	42.5%
	Overall yield	80%	80%	85%
	H/E	1.0	1.0	1.0
Micro-turbine	Electric yield	29%	33%	33%
	Thermal yield	51%	52%	52%
	Overall yield	80%	85%	85%
	H/E	1.8	1.6	1.6
Stirling engine	Electric yield	15%	18%	20%
	Thermal yield	90%	88%	85%
	Overall yield	105%	105%	105%
	H/E	6.0	5.0	4.25
Fuel cell	Electric yield	-	45%	55%
	Thermal yield	-	40%	35%
	Overall yield	-	85%	90%
	H/E	-	0.89	0.6
Steam engine	Electric yield	15%	18%	20%
	Thermal yield	90%	88%	85%
	Overall yield	105%	105%	105%
	H/E	6.0	5.0	4.3
Organic Rankine Cycle (ORC)	Electric yield	15%	18%	20%
	Thermal yield	90%	88%	85%
	Overall yield	105%	105%	105%
	H/E	6.0	5.0	4.3

Table 40 – Hypotheses regarding average yields adopted for each technology

c) Model results

Cogeneration

Technology Fuel	gas turbine with heat recovery natural gas (industry)			
Electrical power Thermal power	30.0 MWe 45.MWth			
Availability	95%			
Development of yields		2010	2015	2020
	Electrical yield	32.0%	32.0%	34.0%
	Thermal yield	48.0%	48.0%	51.0%
Investment	0 k€			
Renovation	€ 150/kWe			
Maintenance	€ 0.012 /kWh e 708 k€/year			

Price of electricity	Market price	€69/MWh
Price of heat	€ 33.6/MWh	

ENERGY EFFICIENCY		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Electrical yield		32%	32%	32%	32%	32%	32%	32%	33%	33%	34%	34%	34%
Thermal yield		48%	48%	48%	48%	48%	48%	49%	49%	50%	50%	51%	51%
H/E		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Primary energy savings (Pe)	Ref E•	52.7%	52.7%	52.7%	52.7%	52.7%	52.7%	52.7%	52.7%	52.7%	52.7%	52.7%	52.7%
	Ref H•	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
	PES	12.3%	12.3%	12.3%	12.3%	12.3%	12.3%	13.4%	14.5%	15.5%	16.5%	17.5%	17.5%

PRODUCTION RECORD		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	Operating hours	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000
PRODUCTS		6 906	7 013	7 123	7 235	7 349	7 465	7 584	7 705	7 828	7 954	8 083	8 214
Electricity	Quantity sold (MWh)	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000	60 000		
	Unit price (€/MWh)	69.4	70.4	71.4	72.4	73.4	74.5	75.6	76.7	77.8	79.0	80.2	81.3
	Product of sale (k€)	4 164	4 223	4 283	4 344	4 407	4 471	4 536	4 602	4 670	4 739	4 809	4 881
Heat	Quantity sold (MWh)	90 000	90 000	90 000	90 000	90 000	90 000	90 000	90 000	90 000	90 000	90 000	90 000
	Unit price (€/MWh)	30.5	31.0	31.6	32.1	32.7	33.3	33.9	34.5	35.1	35.7	36.4	37.0
	Product of sale (k€)	2 742	2 790	2 840	2 890	2 942	2 994	3 048	3 103	3 159	3 216	3 274	3 333
MARGINAL PRODUCTION COST		6 419	6 534	6 652	6 772	6 895	7 020	7 069	7 119	7 172	7 226	7 281	7 415
Fuel	Quantity purchased (MWh) PCI	187 500	187 500	187 500	187 500	187 500	187 500	185 185	182 927	180 723	178 571	176 471	176 471
	Fuel unit price (€/MWh)	27.0	27.5	28.1	28.7	29.2	29.8	30.4	31.0	31.6	32.3	32.9	33.6
	CO2 cost (€/MWh)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
	Expenses (k€)	5 712	5 813	5 916	6 021	6 129	6 283	6 272	6 307	6 343	6 380	6 419	6 535
Maintenance/operating costs (k€)		708	722	736	751	766	781	797	813	829	846	862	880
COMPLETE PRODUCTION COST		6 869	6 984	7 102	7 222	7 345	7 470	7 519	7 569	7 622	7 676	7 281	7 415
Depreciation over 10 years (k€)		450	450	450	450	450	450	450	450	450	450		

FINANCIAL ANALYSIS	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Turnover (k€)	6 906	7 013	7 123	7 235	7 349	7 465	7 584	7 705	7 828	7 954	8 083	8 214
Gross operating excess (k€) EBITDA	486	479	471	462	454	445	515	585	657	729	801	799
	7%	7%	7%	6%	6%	6%	7%	8%	8%	9%	10%	10%
Operating results (k€) EBIT	36	29	21	12	4	-5	65	135	207	279	801	799
	1%	0%	0%	0%	0%	0%	1%	2%	3%	4%	10%	10%
Taxes (k€)	13	10	7	4	1	0	22	47	71	96	275	274
Gross investment (k€)	4 500											
Investment subsidy (k€)												
Net investment (k€)	4 500											
Available cash-flow after taxes/Net cash-flow	-4 026	469	463	458	453	445	493	539	586	633	526	525
Updated cash-flow	-4 026	446	420	396	372	349	368	383	396	408	323	307
VAN project	143											

Figure 47 – Illustration of the tool used to model the profitability of cogeneration facilities

Industry > 12 MWe (excluding specific sectors)

The simulations were carried out for a site having a heat requirement corresponding to an installed thermal power of 45 MWth over 6 500 hours per year. Depending on the technology or the type of sale of the electricity (purchase contract or market), the number of operating hours of the cogeneration facility vary in the model, as indicated in the table below. The complement is provided by a gas boiler.

Given the different hypotheses described previously, the average price of heat for the period considered (12 years) is € 33.6/MW h

The results of the model are as follows:

Alternatives		(1)	(2)	(3)
Cogeneration alone	Operating duration	2 000 hours	5 500 hours	-
	Electrical power	30 MWe	8.5 MWe	
	Investment	4 500 k€	34 773 k€	
	NPV	143 k€	8 138 k€	
Cogeneration + boiler	Operating duration	6 500 hours	6 500 hours	6 500 hours
	Thermal power	45 MWth	45 MWth	45 MWth
	Investment	6 114 k€	36 387 k€	1 614 k€
	NPV	-12 608 k€	4 049 k€	-17 700 k€

(1) Operate on the free market, continuing to use gas
(2) Conversion to biomass cogeneration
(3) Dismantle the cogeneration facility and go back to a gas boiler

Figure 41 – Net present values and investments in the cases studied in the Industry sector > 12 MWe (excluding specific sectors)

Industry < 12 MWe (excluding specific sectors)

The simulations were carried out for a site having a heat requirement corresponding to an installed thermal power of 10 MWth during 6 500 hours per year. Depending on the technology or the type of sale of the electricity (purchase contract or market), the number of operating hours of the cogeneration facility vary in the model, as indicated in the table below. The complement is provided by a gas boiler.

Given the different hypotheses described previously, the average price of heat for the period considered (12 years) is € 30.2/MW h without CO_2 restriction, and € 32.5/MW h with CO_2 restriction.

The results of the model are as follows:

Alternatives		(1)	(1) a	(2)	(3)
Cogeneration alone	Operating duration	3 150 hours	3 150 hours	2 000 hours	-
	Electrical power	6.5 MWe	6.5 MWe	6.5 MWe	
	Investment	2 470 k€	2 470 k€	975 k€	
	NPV	5 601 k€	4 703 k€	-141 k€	
Cogeneration + boiler	Operating duration	6 500 hours	6 500 hours	6 500 hours	6 500 hours
	Thermal power	10 MWth	10 MWth	10 MWth	10 MWth
	Investment	2 758 k€	2 758 k€	1 263 k€	288 k€
	NPV	3 591 k€	2 213 k€	-2 743 k€	-3 630 k€

(1) Renovate the facility to benefit from the purchasing tariff (without CO_2 restriction)
(1) a Renovate the facility to benefit from the purchasing tariff (with CO_2 restriction)
(2) Go on the electricity market
(3) Dismantle the cogeneration facility and go back to a gas boiler

Figure 42 – Net present values and investments in the cases studied in the Industry sector < 12 MWe (excluding specific sectors)

Major heating networks > 12 MWe

The simulations were carried out for a heating network with an installed thermal power of 30 MWth running for 4 000 hours per year. Depending on the technology or the type of sale of the electricity (purchase contract or market), the number of operating hours of the cogeneration facility vary in the model, as indicated in the table below. The complement is provided by a boiler, either gas (cases 2 and 4) or biomass (cases 1 and 3).

Given the different hypotheses described previously, the average price of heat for the period considered (12 years) is € 35.5/MW h

The results of the model are as follows:

Alternatives		(1)	(2)	(3)	(4)
Cogeneration alone	Operating duration	1 500 hours	3 350 hours	-	-
	Electrical power	20 MWe	5.5 MWe		
	Investment	3 000 k€	26 852 k€		
	NPV	1 938 k€	-6 168 k€		
Cogeneration + boiler	Operating duration	4 000 hours	4 000 hours	4 000 hours	4 000 hours
	Thermal power	30 MWth	30 MWth	30 MWth	30 MWth
	Investment	9 752 k€	33 603 k€	6 752 k€	1 019 k€
	NPV	-2 946 k€	-12 434 k€	-3 763 k€	-5 553 k€

(1) Move to biomass boiler to guarantee the heating supply base and put gas cogeneration on the market for the remaining hours
(2) Move to biomass cogeneration
(3) Move to biomass boiler
(4) Move to gas boiler

Figure 43 – Net present values and investments in the cases studied in the major heating networks sector > 12 MWe

Minor heating networks < 12 MWe

The simulations were carried out for a heating network with an installed thermal power of 10 MWth running for 4 000 hours per year. Depending on the technology or the type of sale of the electricity (purchase contract or market), the number of operating hours of the cogeneration facility vary in the model, as indicated in the table below. The complement is provided by a boiler, either gas (cases 2 and 4) or biomass (cases 1 and 3).

Given the different hypotheses described previously, the average price of heat for the period considered (12 years) is € 31.9/MW h without CO_2 restriction, and € 34.3/MW h with CO_2 restriction.

The results of the model are as follows:

Alternatives		(1)	(1) a	(2)
Cogeneration alone	Operating duration	3 350 hours	3 350 hours	-
	Electrical power	6.5 MWe	6.5 MWe	
	Investment	2 470 k€	2 470 k€	
	NPV	5 984 k€	5 054 k€	
Cogeneration + boiler	Operating duration	4 000 hours	4 000 hours	4 000 hours
	Thermal power	10 MWth	10 MWth	10 MWth
	Investment	2 758 k€	2 758 k€	3 735 k€
	NPV	5 462 k€	4 447 k€	-4 054 k€

(1) Renovate the facility to benefit from the C01R purchasing tariff (without CO_2 restriction)
(1) a Renovate the facility to benefit from the C01R purchasing tariff (with CO_2 restriction)
(2) Move to biomass boiler

Figure 44 – Net present values and investments in the cases studied in the minor heating networks sector < 12 MWe

Annex 7 – Summary of progression rates between the alternatives available to cogenerators in the different sectors

Alternative	Progression rate
Industry > 12 MWe (excluding specific sectors)	
Operate on the free market, continuing to use gas	60%
Conversion to biomass cogeneration	20%
Dismantle the cogeneration facility and go back to a gas boiler	20%
Industry < 12 MWe (excluding specific sectors)	
Renovate the facility to benefit from the purchasing tariff	80%
Go on the electricity market	10%
Dismantle the cogeneration facility and go back to a gas boiler	10%
Specific industrial sectors (paper mills, refineries, agri-foodstuffs)	
Steam turbines	
For the wood industry: adapt steam turbine facilities to integrate ERC CFTs or the biomass purchasing tariff	50%
No modification compared to the current situation	50%
Gas facilities under the OP < 12 MWe	
Renovate the facility to benefit from the purchasing tariff	80%
Dismantle the cogeneration facility and go back to a gas boiler	15%
For cogeneration facilities installed in agri-foodstuffs industries: conversion of facilities to biogas	5%
Gas facilities under the OP > 12 MWe	
Go on the market	30%
Biomass conversion	30%
Dismantle the cogeneration facility and go back to a gas boiler	40%
Major heating networks > 12 MWe	
Move to biomass boiler to guarantee the heating supply base and put gas cogeneration on the market for the remaining hours	40%
Move to biomass cogeneration	30%
Move to biomass boiler	20%
Move to gas boiler	10%
Minor heating networks < 12 MWe	
Renovate the facility to benefit from the C01R purchasing tariff	60%
Move to biomass boiler	40%
Collective residential and Tertiary > 36 kWe	
Renovate the facility to benefit from the C01R purchasing tariff	70%
Move to gas boiler	20%
Go on the electricity market	10%
Move to biomass boiler	0%

Annex 8 – Context of micro-cogeneration in France

a) Regulatory context

The micro-cogeneration threshold is set at 36 kVA in France given EDF subscription ranges and connection contracts. For these small facilities of less than 36 kVA, there is an obligation to purchase at the tariff of around 8 euro cents/kWh, corresponding to the pre-tax regulatory tariff. The eligibility conditions defined in the order of 3 July 2001 impose a primary energy saving greater than 5% and a Heat/Electricity ratio > 0.5.

This feed-in tariff encourages the individual to prefer auto-consumption of their electricity production rather than selling it, the purchase price being around 11 euro cents/kWh.

The feed-in arrangement is optional. It incurs a connection cost of € 200 to € 400 including tax and annual management and metering fees invoiced by ErDF at € 57 including tax. The sale of the electricity is only attractive on condition of having an excess of electricity production of more than 1 000 kWh of electricity which may not be auto-consumed[21]. Sale can therefore only be considered by those homes having significant heating requirements. Without feed-in, the electricity injected into the network is ceded to ErDF.

b) Technical and economic context

A range of gas micro-cogeneration boilers, essentially based on Stirling technology, is in the process of appearing in France. The main manufacturers expect marketing to begin between 2010 and 2011. These manufacturers (De Dietrich, Baxi, Viessmann, Bosch, Vaillant and Whispergen) propose a product integrating micro-cogeneration in a condensing boiler. The product is compact and resembles a classic boiler. The electricity production is relatively low, with an engine power of around 1 kWe. Stirling technology offers the possibility to have a system with very high overall yield, low NOx emission, easy maintenance and producing little noise. The electrical yield remains limited, however (< 20%).

GDF SUEZ has launched a large-scale programme of demonstrations. An initial campaign of experiments with 40 units in single family houses was carried out in 2007 in the Rhône-Alpes region. A deployment of 200 to 300 units is planned by GDF SUEZ in 2010, during renovation and in new housing.

The price of these pre-series is today around € 10 000 before tax. It is, however, expected that with series production, the price of these micro-cogeneration boilers will rapidly approach that of the condensing boiler + individual solar water heater solution, or around € 7 000 before tax.

[21] In the context of the experiment carried out by GDF-SUEZ relating to 40 eco-cogenerators in single family houses in the Rhône-Alpes region, an average auto-consumption of 56% was observed.

In addition to these new gas products, a Stirling micro-cogeneration boiler operating on wood pellets is being marketed in France. Sunmachine, the German manufacturer of this micro-cogenerator with an electrical power of 3 kWe and a thermal power of 15 kWth, offer this product for around € 23 000.

New products based on Organic Rankine Cycle (ORC) technology are appearing on the market. Different fuels may be used. The electrical yields are in the region of 12 - 15%, close to those of Stirling engines.

Some manufacturers (Senertech, Vaillant), offer cogeneration by internal combustion engine. The electrical powers are in the region of 5 kWe, but products with electrical powers of 1 kWe have also been developed. The electrical yields are in the region of 20 - 28%.

With increasing electricity demand, and decreasing heat demand, those technologies with low electricity/heat ratios will be replaced in the future by fuel cells which adapt better to the development of uses within the construction field.

The table below resumes the situation of the different micro-cogeneration technologies.

	Internal combustion engines	Stirling engines	Rankine Cycle	Fuel cells
Maturity	++++	+++	++	+
Electrical powers	From 1 kW	1 to 9 kW	2 - 36 kW	From 1 kW
Yield on LHV	70 to 100%	85 - 105%	~ 100%	75-90%
H/E ratios	1/2 to 1/4	1/5 to 1/8	1/8 to 1/10	1/2 to 1/3
Number of manufacturers in Europe	5	8 to 10	3	6
Advantages/ disadvantages	High maintenance, significant emissions, noise	Can be integrated for small powers in boilers	Low H/E but fuel flexibility, wide power range	Very high H/E ratio, quiet, very low emissions, product life time to be tested

Table 45 – Summary of micro-cogeneration technologies (extract GDF SUEZ doc.)

A gas micro-cogeneration boiler for Residential uses < 36 kWe appears on the market. The products remain expensive, but may conquer a share of the market in new construction to the extent that only the most efficient technologies are authorised, which are all expensive. Their penetration into existing construction seems today a little more difficult. In addition, technologies based on biomass still require developments. Some biomass micro-cogeneration systems are in the process of being introduced to the market. However, the investment costs are very high and the reliability of this equipment remains to be tested.

c) Prospects for regulatory developments

RT 2012 and new single family houses

In the context of the future thermal regulation of construction, it is planned to impose an obligation on the single family house to resort to a source of renewable energy via a connection to a heating network supplied to more than 50% by REs, or to a CESI, or to demonstrate that the energy consumption of the building includes at least 5 kWh/m_2 of primary energy produced from at least one source of renewable energy.

The only alternatives would be to resort to the production of domestic hot water by an individual thermodynamic domestic hot water production appliance with a good efficiency level or to resort to the production of heating and/or domestic hot water by a micro-cogeneration boiler using liquid or gaseous fuel.

The micro-cogeneration boiler presents fewer installation constraints (roof orientation) than the CESI. In addition, even if the investment cost for the micro-cogeneration boiler is today in the region of € 10 000 before tax, it should drop rapidly to reach € 7 000 before tax and be close to the reference 'condensing boiler + CESI' solution.

The low thermal requirements in new housing will not lead to significant electricity production, thereby limiting the attractiveness of their distribution in new construction. While the micro-cogeneration boiler has been developed for individual heating, it may well be integrated into collective heating as a basic production system coupled with other heat generators. Several units may also be installed in series, enabling increased electricity production. This type of installation would enable an increase in the operating hours of micro-cogeneration boilers. As the electricity production increased, the electric bills would be reduced and the profitability of the appliance improved.

RT 2005 in existing buildings

Title V 'Micro-cogeneration boiler in existing buildings' has been validated to integrate into the regulatory calculations a micro-cogeneration boiler project in existing buildings with individual heating. This title may also be extended to collective heating. The micro-cogeneration boilers in the process of being commercialised may be considered in collective construction as a basic system associated with another boiler.

Other measures being discussed

Ecodesign

The Ecodesign directive is aimed at reducing consumption by equipment using energy. The measures which will be implemented consist of eliminating equipment with poor performances from the market by setting minimum performance levels and by informing buyers of the energy performance through product labelling. Performance thresholds in terms of efficiency and NOx emissions are being established. Standard boilers will be prohibited by 2013/2015. In the context of the Ecodesign directive, micro-cogeneration solutions will be among the most efficient systems.

Tax credit

The income tax credit for expenditure on equipment for the main residence is aimed at promoting the most efficient work and equipment for the home in terms of energy savings. This fiscal arrangement, which applies until 31 December 2012, supports efficient heating solutions. For this reason, efficient micro-cogeneration boilers could be eligible for the tax credit. Discussions are in progress.

EEC

A standardised operation sheet for micro-cogeneration boilers is in the process of being published. It should be integrated during the next order at the end of 2010.

d) Attractiveness of micro-cogeneration in France

Reduce primary energy consumption

Micro-cogeneration is an efficient solution to make primary energy savings compared to separate production of heat and electricity. The primary energy savings for micro-cogeneration integrated in a boiler such as those being introduced on the market (with an overall yield of 107%) are in the region of 25% according to the calculation method in Directive 2004/8/EC.

Diminish the electricity peak

Micro-cogeneration is positioned as a solution to reduce the peak in electricity demand. France has significant dependence in terms of its electrical consumption on the temperature gradient due to the wide distribution of electric heating. The current development of heat pumps is not necessarily positive from the point of view of the peak in demand to the extent that it substitutes in part for non-electric heating. In addition, heat pumps contribute to reinforcing the variation in electricity demand against the temperature gradient due to the fact that their performance decreases as the temperature decreases. However, as micro-cogenerators produce electricity during these periods of heating demand, they may contribute to reducing the peak in electricity consumption. Peacock and Newborough (2006) demonstrated that the integration of 1 kWe Stirling micro-cogenerators into housing stock with penetration rates of 23% and 77% respectively enable the reduction in the peak of electricity demand for this housing by around 11% and 37% in the winter.

Impacts on the network

The distribution of micro-cogeneration in France may contribute to securing the electricity network. It has the advantage of being a decentralised production system which is well aligned with electricity demand since it is linked to heating demand. It may permit the transfer to users of a part of the investment in new means of electricity production. It may also avoid investments in the reinforcement of networks in areas under constraints (PACA, Brittany). This technology offers the advantages of ease of insertion into the urban environment and short lead times.

It also permits the avoidance of network losses (evaluated at 7.5% for a connection to the low voltage network and 14% if auto-consumed according to Directive 2004/08/EC)

Annex 9 – Detailed hypotheses regarding the sector macro development model

Hypotheses regarding cogeneration technologies

For each of these sectors, the model is based on a predominant technology, depending on the fuel:

	Biomass	Biogas	Gas excluding OP	Gas under OP	Other cogen.
Industry > 12 MWe	Steam turbine (ST)	-	Gas turbine (GT)	Gas turbine (GT)	Steam turbine (ST)
Industry < 12 MWe	-	-	Gas turbine (GT)	Gas turbine (GT)	-
Specific industrial sectors (paper mills, refineries, agri-foodstuffs)	Steam turbine (ST)	Internal combustion engine (ICE)	Gas turbine (GT)	Gas turbine (GT)	Steam turbine (ST)
Major heating network (> 12 MWe)	Steam turbine (ST)	-	Gas turbine (GT)	Gas turbine (GT)	Steam turbine (ST)
Minor heating network (< 12 MWe)	-	-	50% GT; 50% ICE	50% GT; 50% ICE	-
Collective residential and Tertiary > 36 kWe	-	-	50% GT; 50% ICE	50% GT; 50% ICE	-
Residential < 36 kWe	-	-	Stirling engine	-	-

Table 46 – Hypotheses regarding the dominant technology by sector and by fuel

For the whole model, the durations of operation of each of the technologies considered are those given in Table 21 on page 45.

Annex 10 – Calculation method for CO_2 emissions avoided

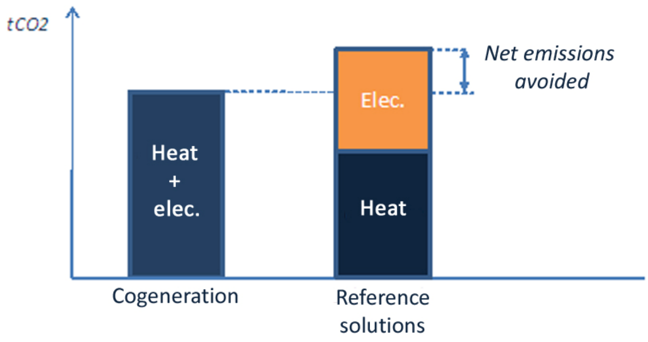


Figure 48 – General principle for the accounting of CO_2 emissions from cogeneration

1. Electricity production by cogeneration: include only those CO_2 emissions due to the production of electricity by cogeneration (the production of heat is assumed to meet a need which must be satisfied and is therefore removed):

   Cogeneration electricity production CO_2 =

   Total cogeneration CO_2 (heat + electricity) - classic boiler CO_2

   with classic boiler CO_2 being CO_2 emissions linked to the production of the same quantity of heat with a classic boiler operating on the same fuel as the cogeneration facility

   Given the yield hypotheses adopted for the different technologies, the emission factors for the production of electricity by cogeneration are the following:

	Hypotheses						Results	
	Fuel	Heat only	Cogeneration 2010		Cogeneration 2020		Cogen. elec. 2010	Cogen. elec. 2020
	EF $kgCO_2/MWh$	• ref.	• elec.	• heat	• elec.	• heat	EF $kgCO_2/MWh$	EF $kgCO_2/MWh$
Biomass	0	86%	14%	76%	14%	76%	0	0
Biogas	0	70%	40%	40%	42.5%	42.5%	0	0
Gas (Industry and HN > 12 MW)	231	90%	32%	48%	34%	51%	337	294
Gas (HN < 12 MW and Coll. & Tert.)	231	90%	36%	45%	38%	48%	321	283
Other cogen.	264	80%	14%	76%	14%	76%	95	95

Table 47 – Emission factors (EF) of CO_2 from the production of electricity by cogeneration depending on fuel (sources: Decision 2007/589/EC [4] and Annex II of Directive 2007/74/EC [2])

2. Emissions avoided: deduct the emissions which would have been caused by another method of electricity production.

   The replaced production method has been assumed systematically to be a combined gas cycle with a 55% yield; according to Decision 2007/589/EC[4], the corresponding CO_2 content is therefore: 231 [kgCO_2/MW h]/55% = 420 [kgCO_2/MW h].

Annex 11 – Calculation method for primary energy savings achieved

The methodology used during the study to calculate the primary energy savings is that described in Annex III of Directive 2004/8/EC [1].

The reference yields used for the calculation of primary energy savings result from Decision 2007/74/EC [2]:

- For the separate production of electricity:
  - In compliance with Annex III of Decision 2007/74/EC, a climatic correction factor has been applied. The annual average temperature in France is 13°C (source: IFEN), or a gain in yield of 0.2% compared to ISO conditions (15°C).
  - The reference yields used (excluding correction) are the following (Annex I to Decision 2007/74/EC):
    - Natural gas: 52.5%
    - Biomass (wood): 33%
    - Biogas: 42%
    - Other fuels: 25%
- For the separate production of heat, the reference yields used are the following (Annex II to Decision 2007/74/EC):
    - Natural gas: 90%
    - Biomass (wood): 86%
    - Biogas: 70%
    - Other fuels: 80%

The conversion to toe of primary energy saved is done by converting the primary energy savings thus calculated, expressed as a percentage, into theoretically non-consumed quantities of fuel.

Annex 12 – Hypotheses regarding the calculation of the total investment cost to achieve the economic potential

The technologies considered for each segment are those detailed in Table 46, page 112. The associated costs used are those from the first part of Annex 6.

In addition, an average gain of € 50/kW in cogeneration sold when it is dismantled has been considered.

Finally, the different costs have been considered as constant over the period studied.

Annex 13 – Calculation method of the weight on the SCOPE of the achievement of the economic potential

The expenses of the public services linked to the obligation to purchase are financed by all consumers via the contribution to the public electricity service (SCOPE). The calculation of these expenses is based on the comparison between the cost of purchase corresponding to the payments made by the buyers to the producers, and the cost avoided by these buyers linked to the acquisition of the corresponding electricity. The cost avoided is determined in reference to the market price.

The market price adopted is € 50/MWhe in 2010. In addition, the following average levels have been adopted for the different purchasing tariffs for 2010:

- OP gas tariff: between € 106/MWhe (EP > 12 MW) and € 119/MWhe (EP < 12 MW)
- Biomass purchasing tariff: € 150/MWhe

In addition, the hypothesis of an annual increase of 2% in market prices and purchasing tariffs has been made.

Annex 14 – Detailed hypotheses concerning cogeneration for cooling

Cooling requirement

The cooling requirements used in the study were established from different sources.

The following hypotheses for growth have been considered:

- Industry: 0%
- Tertiary: 4.3%
- Residential: 2.5%

Technical potential

The hypotheses adopted to establish the technical potential specifically linked to cogeneration used for cooling are as follows:

- No additional electrical capacity: we have considered that cooling by cogeneration would almost exclusively be done by trigeneration (cooling, heat and electricity production)
- Trigeneration cooling networks may cover 2% of total cooling requirements (value established on the basis of the order of magnitude of facilities installed in 2010) and this rate is assumed to be identical by 2015 and 2020, the economic conditions being assumed to be unchanged.
- The duration of operation for cooling has been assumed to be that of some cases known in current facilities; around 1 440 hours
- The performance coefficient of the absorption technology has been assumed to be equal to 1
- The hypothesis has been made that the technologies used would be gas engines and gas turbines (50%/50%), with a overall efficiency of 85% on average, and H/E ratios of 1.3 for the gas engine and 1.5 for the gas turbine
- Trigeneration may meet 88.6% of the total cooling requirement of a site (according to [25])