

The Future of Cogeneration and Heat Supply to Industry and Greenhouse Horticulture

Report

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The future of CHP and the supply of heat to industry and greenhouse horticulture

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Summary

CHP or cogeneration - high efficiency combined heat and power generation - is having a difficult time in current market conditions. This could lead to the shutting down of CHP plants, which could adversely affect energy use and emissions.

The Ministry of Economic Affairs has therefore asked CE Delft and DNV GL to map the future position of CHP, focusing specifically on the position of flexible CHP in a market with a high level of renewable capacity, and the possible alternative solutions for meeting the heat demand.

Market position of CHP in 2020 and 2030

The detailed simulation of the North-West European market indicates that the current weak position of CHP in the market will not improve of its own accord in the coming years. The simulation model shows that, based on their variable costs, must-run CHPs cannot operate economically and flexible CHPs barely manage to do so. If we also take investments into account, more than half of CHP installations will have a financial gap by 2020.

The remaining installations will be reasonably cost-effective. This calculation is based on an IEA baseline scenario for fuel and CO₂ price changes and the agreements in the SER [Social-Economic Council] Energy Agreement for the development of renewable energies. The financial gap model used by the ECN [Energy Research Centre of the Netherlands] until 2009 to determine CHP subsidies under the SDE renewable energy incentive scheme were used for the calculations. The financing costs are calculated on the basis of 80% borrowed capital at a 6% return, and 20% equity at a 15% return.

The simulation shows that, under the anticipated market conditions, other gas-fired power stations will be in an even more difficult position. The picture that emerges from the simulation model is that CHP installations will be in a better market position in 2030 than in 2020. By then, much of the fossil and nuclear capacity in Germany, Belgium and the Netherlands will have been decommissioned, pushing up electricity prices. This calculation is based on capacity as at 1 January 2014, and does not allow for the fact that many CHP installations may already have been decommissioned by then.

The position of CHP installations in 2030 was also studied under other market conditions, showing that:

- High CO₂ prices (€ 70/MT CO₂) significantly improve the position of CHP making all types of installation cost-effective.
- This is also the case when a mark-up is applied to electricity prices (an additional increase which may be added to production prices when there is a shortage in the market).
- Strong growth of renewable energy weakens the position of CHP, by reducing electricity prices. The same is true of other fossil units.

Effect of shutting down CHP on CO₂ emissions and primary energy use

Shutting down CHP installations will probably lead to a substantial increase in CO₂ emissions and energy use. The simulation shows that electricity production will be taken over by less energy-efficient fossil units. The most obvious options are Dutch gas-fired power stations or foreign coal-fired power stations. The latter is the most likely according to the simulation. If half of the CHP capacity (4.6 GWe) is replaced by coal-fired power stations, CO₂ emissions will increase by 8 Mt, and primary energy use by 40 PJp. This is considerably lower if they are replaced by gas-fired power stations (0.6 Mt CO₂ emissions, 11 PJ primary energy use). Final energy use does not change. If more capacity is shut down, CO₂ emissions increase by 12 Mt (coal) and 0.9 Mt (gas) respectively. Most of the CO₂ emissions are below the ceiling set in the EU ETS.

Position of flexible CHP

Flexible CHP installations can respond to variations in electricity prices by temporarily increasing or reducing electricity production. The CHP installations in greenhouse horticulture are highly flexible. In industry around half of installations have some degree of flexibility. The analysis shows that flexible units in industry and greenhouse horticulture achieve a consistently higher economic return than CHP units which cannot operate flexibly.

Flexible CHP can also respond to surpluses with Power-to-Heat, the conversion of surplus electricity into heat, particularly in a scenario with high level renewable energy.

There are technical possibilities for making must-run CHPs flexible so that they are able to respond to fluctuations rapidly (in less than an hour) and fully (0-100%). The cost of converting existing must-run CHPs (ca 20% of CHP facilities) is around € 75 million to € 150 million. Converting CHPs to flexible operation may reduce energy savings. Fiscal provisions and transport charges may also add to the costs as, for example, installations are only exempted from gas taxes if their electrical efficiency is over 30%.

Alternatives for industrial heat supply

Industry uses various sustainable alternatives to produce heat. One route is generating steam from waste. This appears to be technically and economically feasible, but has very limited potential. Biomass and geothermal energy have greater potential, but are only cost-effective if they are subsidised. However, sustainable heat in industry can be a relatively cheap option for achieving sustainable energy targets.

1 Introduction

1.1 Background

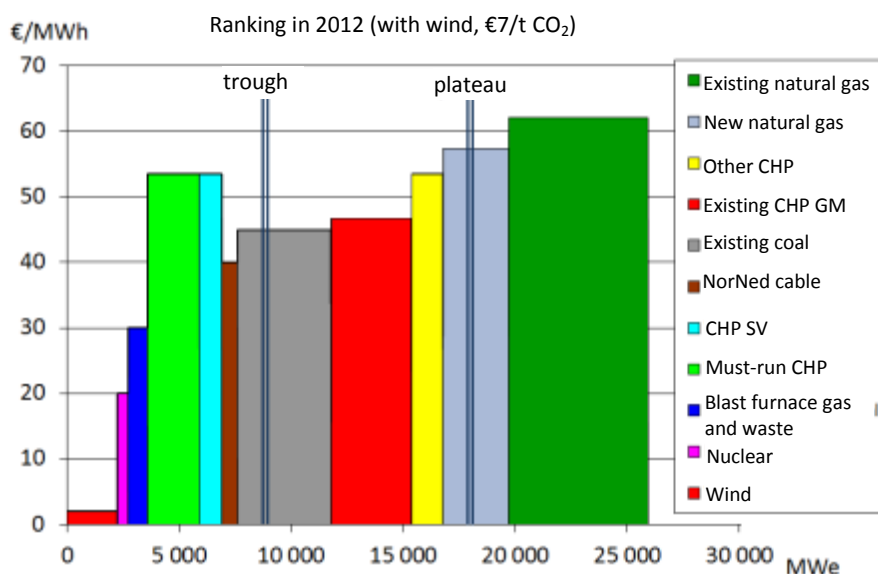
In the SER Agreement on energy for sustainable growth (SER, 2013) it was agreed that the government and companies would investigate the options for meeting the industrial heat demand sustainably.

The background to this agreement is that industry accounts for a substantial part of the national heat demand, most of which is supplied by CHP. CHP, or cogeneration, is an efficient technique for producing electricity and heat from fuels, typically achieving efficiency levels of 75-94%.

However the current market conditions, with relatively high gas prices and low electricity prices, are unfavourable for CHP. This is illustrated in Figure 1, the ranking in the Dutch electricity network in 2012.

The figure shows that the average variable production costs of CHPs are higher than those of both wind energy and coal capacity.

Figure 1 Ranking in the Dutch electricity network in 2012



Source: Energy Matters, 2012

The unfavourable position of CHP in the market is the result of a combination of coinciding factors (limited growth of demand, plentiful renewable energy from Germany, growth of the production capacity of fossil power stations, low coal prices, relatively high gas prices, low CO₂ prices). The relatively high gas prices coupled with low electricity prices produce an unfavourable earning model for gas-fired CHP installations. Under these conditions CHP capacity is shut down, potentially resulting in less efficient generation of heat and electricity and leading to higher energy use and higher CO₂ emissions in the production chain.

This being the case, the high costs of heat production are a concern, given the economic position of energy-intensive sectors.

In view of this, the Ministry of Economic Affairs needs to gain an insight into the future position of CHP, including an idea of the expected installed CHP capacity in 2020 and 2030, how much of this capacity will be shut down and, by extension, what this means for energy use and CO₂ emissions.

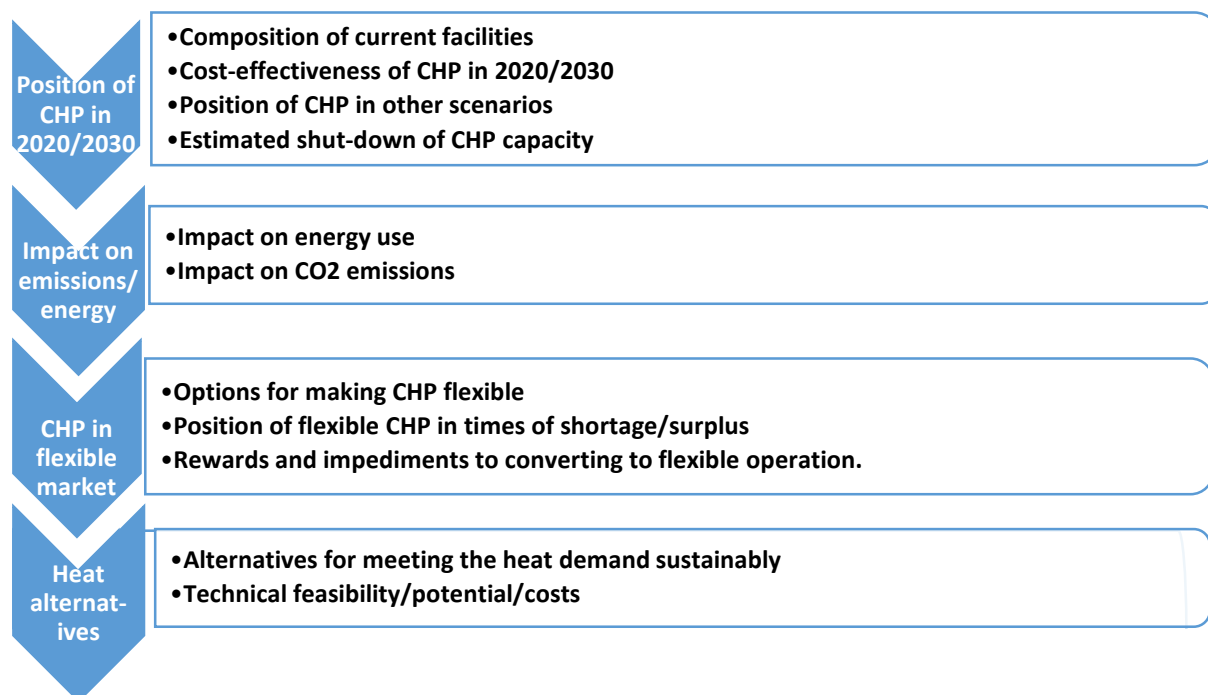
It should be noted here that a large number of CHP installations fall under the EU ETS system, including installations providing substitute production. There is no national CO₂ policy for installations under the EU ETS and the Netherlands has only formulated a target for final energy use.

As the production of solar and wind energy will grow sharply in the next few years, the position of flexibly operated CHP installations should be considered here. These are CHP installations which can be started up quickly when wind and solar produce too little electricity, and shut down when there is a plentiful supply. Another question is what alternatives there are to CHP: what are the possibilities for meeting the industrial heat demand in a (relatively) sustainable way?

This report describes the results of a study of these questions. Industrial parties have also expressed a need for an insight into the future heat costs of Dutch industry, and a comparison with the situation in other countries. The study examines the costs of generating heat in CHP installations, in comparison with sustainable alternatives, such as biomass and geothermal energy. However, it does not compare the situation in the Netherlands with that in the surrounding countries.

The study was carried out jointly by CE Delft and DNV GL for the Ministry of Economic Affairs. Guidance for the study was provided by a steering committee of representatives from the industry organisations VNCI (chemical industry), VNP (paper industry), Cogen Nederland (CHP installations), LTO Glaskracht and Energie Nederland (energy production companies). Guidance for the case studies was provided by a feedback group of representatives from various industrial sectors. A list of the members of the steering group and feedback group can be found in Annex A.

Questions studied



1.2 Study method

The study uses *two models*:

1. the first is a detailed simulation model which describes the energy system in the Netherlands and the market in North-West Europe on an hourly basis;
2. results from this simulation model are used in a business-case model, which calculates the cost-effectiveness of investments in CHP and other options.

Case studies of various companies were carried out for the third question. These provide information about practical experience of making the heat demand sustainable. A desk study of recent information from research programmes was also carried out. The results of the case studies were reviewed by a feedback group of representatives from industry (the members are listed in Annex A).

1.3 Reading guide

This report begins in Chapter 2 with a summary of the CHP production capacity as at 1 January 2014. It covers the installations in industry, greenhouse horticulture and the built environment. These are subdivided into must-run and flexible capacity. We describe the developments in installed CHP production capacity, and in the production of electricity and heat in CHP installations.

The third chapter describes the position of these CHP installations in 2020 and 2030 on the basis of model calculations made in the simulation model for the North-West European market. Model calculations were made for various scenarios for the amounts of renewable energy and price trajectories. Business-case calculations were then made with a cost-effectiveness model. The model analysis is based on current capacity, with no allowance for the possible shut-down of CHP installations in the intervening period. However, the analysis does show how much of the CHP capacity in 2020 will be operating at a loss and will probably be shut down. The next chapter, Chapter 4, describes the impact of shutting down CHP installations on energy use (final and primary) and CO₂ emissions. Chapter 5 describes the position of flexible CHP in a production system that includes a large amount of renewable energy production capacity. The analysis focuses on the CHP installations in the industry and greenhouse horticulture sectors. Chapter 6 describes efficient and sustainable ways of meeting the heat demand in industry and greenhouse horticulture instead of, or in addition to, CHP, based on case studies of five companies (Akzo Nobel, Ammerlaan-TGI, AVEBE, Eska Graphic Board and Parenco), and a desk study. The report ends with conclusions.

2 Composition of existing CHP capacity

This section outlines the current composition of CHP capacity and how it has developed in recent years. This information is classified by the various types of CHP installation and the sectors in which they are located. This section answers the following questions:

- How much CHP capacity is must-run and how much is flexible?
- How much CHP capacity has been shut down in recent years?

In addition to the information in this chapter, Annex B provides background information about the age profile of the CHP capacity and the development of CHP installations in the period 2000-2012.

2.1 Existing CHP capacity as at 1 January 2014

Table 1 shows the composition of the existing CHP production capacity on the reference date 1 January 2014. The data come from the Energy Matters¹ database.

Table 1 Installed CHP production capacity as at 1 January 2014 (excluding coal, in MWe)

	<i>Gas engines</i>	<i>STEG</i>	<i>Gas turbines</i>	<i>Steam turbines</i>	Total
Industry	-	2 316	373	174	2 863
- refineries	-	667	21	24	712
- food industry	-	147	117	62	326
- chemical industry	-	1 006	153	74	1 233
- paper industry ²	-	208	4	6	218
- other industry	-	288	78	8	374
Greenhouse horticulture	3 060	-	-	-	3 060
Built environment	580	2 055	-	321³	2 956
Total	3 640	4 371	373	495	8 879

Source: Energy Matters, 2014

The total installed CHP production capacity is 8.9 GWe⁴. The majority, ca 8.4 GWe, is powered by natural gas. A small proportion is powered by other fuels, such as waste, furnace gas and industrial waste gases. STEGs (4.4 GWe) and gas engines (3.6 GWe) account for most of the capacity. Gas turbines (0.37 GWe) and steam turbines (0.5 GWe) account for a smaller share.

¹ This database is based on surveys of members of Cogen Nederland, databases of types of CHP installation and customer contacts. The latter is mainly information from the past few years about the use of CHP from industrial censuses and demolition records.

² According to the VNP, the installed STEG capacity is lower than the gas turbine capacity. However, the total installed capacity does tally with the industry organisation's estimate.

³ Excluding 600 MWe from the (coal-fired) Amercentrale power station.

⁴ This does not include the coal-fired Amercentrale.

The majority of CHP installations date from 1985 to 2005, with a peak between 1995 and 2000. The peak in greenhouse horticulture falls in 2000 to 2005. Many CHP installations are thus about 15 to 20 years old. Annex B gives a more detailed picture of the age profile of CHP, and the age profile of STEGs and gas engines in greenhouse horticulture.

The CHP installations produce a large proportion of Dutch electricity, amounting to 42% in 2012 (see also Table 4 in Section 3.2 and Figure 29 in Annex H).

2.2 Flexible and must-run

CHP units are designed to connect the production of heat and electricity. In a CHP installation heat is always produced in combination with electricity. The extent to which a CHP can vary its electricity production – while producing a constant amount of heat – determines its flexibility. Units which have little flexibility are called ‘must-run’. There are also CHP units in industry which produce heat, and vary their electricity production in relation to their heat production. This allows them to respond to electricity price variations: when prices are high, they produce heat and electricity, when prices are low they produce only, or mainly, heat. These are called flexible units.

Some units are also able to store heat temporarily in a heat buffer, allowing them to break the connection between heat supply and demand. This is only possible if heat is produced as hot water. One example is the gas engines used in greenhouse horticulture which can be shut down and started up quickly, using heat buffers, so that they can be run when the electricity price is high and the heat demand arises later. The CHP installations in greenhouse horticulture can therefore supply electricity during the day and use the heat for heating at night.

Table 2 shows the main options for converting CHP installations to flexible operation. The first two options require a boiler capable of producing steam independently from natural gas. In the first case a boiler is installed and in the second the flue gas boiler is modified. In principle, 100% flexibility can be achieved with these options. Heated boilers have start-up times of less than an hour.

The bottom option in the table shows that some degree of flexibility can often also be obtained by running CHP installations at part load, so that the installation is not operating at full capacity and produces less electricity. The possibilities for this are limited, as the installations are less energy efficient at lower capacities (see figure in Annex C, part f), and the NO_x emissions can also rise. Typically, capacities can be reduced to a maximum of 75% thermal and 50% electric. The various flexibility options are discussed further in Annex C.

Table 2 Options for making CHP installations more flexible

Flexibility option	Degree of flexibility	Start-up speed	Typical conversion costs	Basic conditions
Addition of a separate boiler	0-100%	GT: 10-20 min STEG: 30-60 min	€ 120-150/kW	Requires enough space on site
Installation of burners in flue gas boiler and additional combustion air blower	0-100%	GT: 10-20 min STEG: 30-60 min	€ 30-40/kW	Technically complex modification. Requires enough room in flue gas pipe
Addition of heat buffer	0-100%	<30 min	Ca € 250/m ₃ storage	To be used only for CHP installations which produce hot water (greenhouse horticulture, district heating)
Part-load operation	75-100%	<15 min	Limited, provided there are variable intake blades (generally the case)	If an installation runs at part load, it is less efficient and NO _x emissions can rise

Source: Energy Matters

On the basis of information from Energy Matters (2014) a distinction was made between three types of CHP flexibility:

- *must-run*: has an hourly fixed profile for heat and electricity production;
- *partial spark-spread*: has an hourly fixed profile for heat production and the accompanying minimum electricity production; can produce additional electricity in hours when the electricity price is high;
- *flexible*: has a fixed hourly heat demand but no restrictions on electricity production, decides whether to produce the required heat in CHP mode or pure steam mode or to use a gas boiler. This breaks the connection between heat production and electricity production.

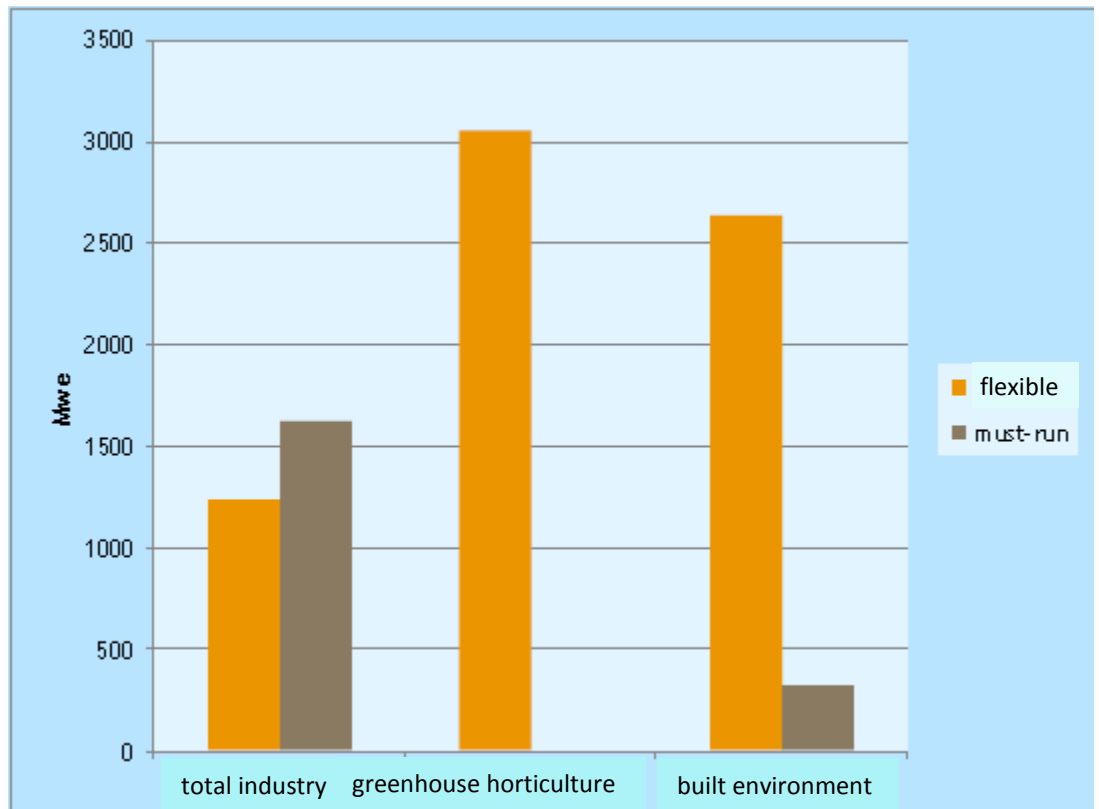
Annex B classifies installed capacity by these three categories.

This classification was used in the simulation calculations for the position of CHP in the energy market in 2020/2030 (Chapter 3), which showed that the partial spark-spread units operate virtually identically to the must-run units: they do not make use of the option to produce additional electricity. The partial spark-spread installations are therefore merged with the must-run units for the rest of the analysis.

Figure 2 classifies the installed production capacity according to must-run (including partial spark-spread) and flexible. The installations are allocated on the basis of information from Energy Matters which has not been verified by the companies themselves and is thus indicative. A total of 1.95 GW is classified as must-run and 6.93 GW as flexible. 1.62 GWe of the installations in industry is flexible. This is specified in more detail in Figure 9 in Annex B.

Figure 3 shows that around half of the CHP installations in industry are regarded as flexible. In greenhouse horticulture all CHP units (gas engines) can be used flexibly. In the built environment most of the CHP installations are technically capable of operating flexibly, but the structure of energy taxes, which have an electrical efficiency requirement, means that they actually operate as 'must-run'. The units are generally equipped with auxiliary heating boilers, and are therefore technically capable of switching from supplying heat from the CHP to supplying heat from the boilers.

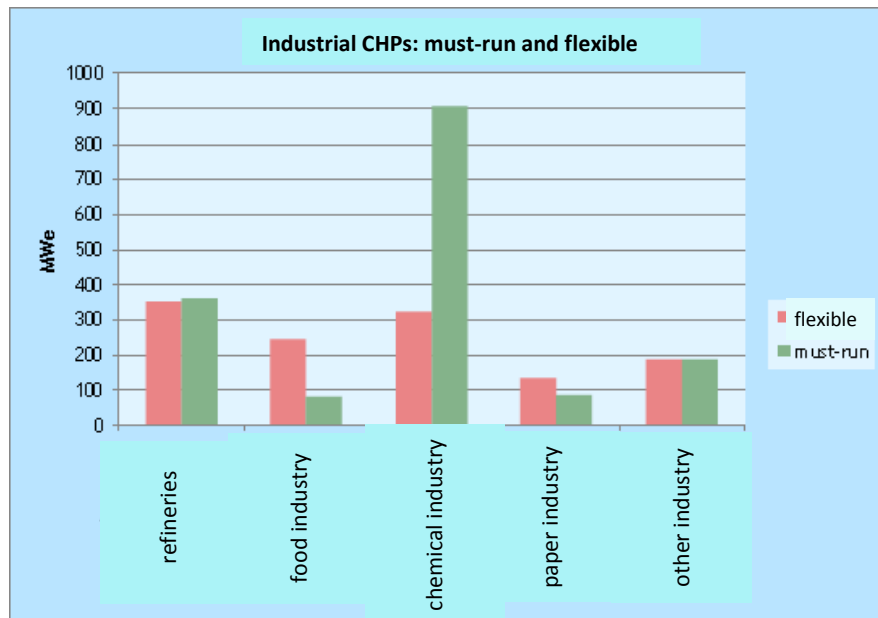
Figure 2 Flexible and must-run CHP capacity in industry, greenhouse horticulture and the built environment



Source: Energy Matters

This is further specified by industry in Figure 3, which shows that the paper and food industries in particular have CHP installations that can be operated flexibly. In the chemical industry, the majority of the installed capacity is 'must-run'.

Figure 3 Specification by industrial sector



Source: Energy Matters

2.3 Development in recent years

The installed CHP capacity has fallen significantly in the past three years. According to Energy Matters the industry has decommissioned 996 MWe in the past four years, 511 MWe permanently, while 485 MWe has been mothballed.⁵ This can also be seen from a comparison with figures from Statistics Netherlands, according to which a further 3.1 MWe were installed in 2012.

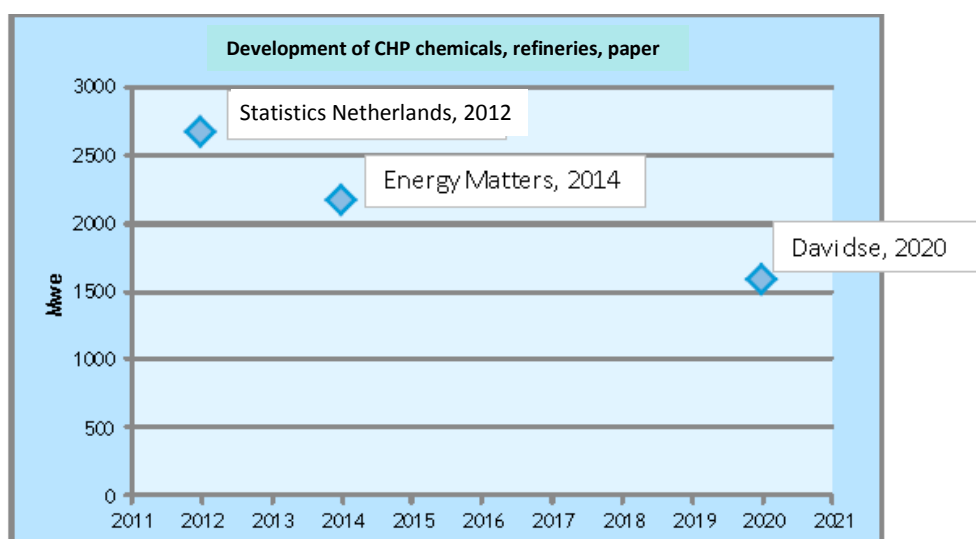
In addition to the phasing-out of CHP installations this can probably be explained largely by definitions, as the Statistics Netherlands figures still include coal-fired CHP and waste incineration installations and may also not be quite as up-to-date.

⁵ The difference between the fall shown in the Statistics Netherlands and Energy Matters figures is probably due to the fact that the Statistics Netherlands database is less up-to-date.

The fall in installed capacity is consistent with the results of a study conducted by Davidse Consultancy in 2012⁶. This study gives an indication of the CHP capacity expected to be shut down in the chemical, paper and refineries sectors. The data were collected from a survey of companies. According to the report 915 MWe CHP capacity is expected to be shut down in these three sectors in the period up to 2020. The chemical industry also recently reported in its 2013 sustainability report that many CHP installations were shut down in 2012.⁷

Figure 4 compares the Statistics Netherlands and Energy Matters figures with Davidse's forecasts.

Figure 4 Development of installed CHP capacity in the refinery, chemical and paper industry sectors



⁶ Davidse Consultancy, 2012, Warmte-energy, de motor van de industry, 2012 <http://www.vnpi.nl/Files/file/20121021%20Davidse%20Rapport%20Warmteonderzoek%20MEE%20definitief.pdf>.

⁷ As a result of the shut-down of CHPs, the chemical industry produced 20% less electricity in 2012 than in 2011, leading to an increase in indirect CO₂ emissions (VNCI [Association of the Dutch Chemical Industry], Rapport Duurzaamheid 2013).

3 Position of CHP in the energy market in 2020/2030

In this chapter we examine the economic position of CHP in the future energy market. The central question is: *how cost-effectively will CHP installations operate in 2020, and what will the situation be in 2030?* We will first use a simulation model to look at the future energy market and the position of CHP installations in that market on the basis of variable costs and benefits. We will then look at the investments that will be needed to keep CHP installations running, and the impact of this on their cost-effectiveness.

Specific questions are:

- What is the position of CHP installations in 2020/2030?
- How much of the CHP capacity is likely to be shut down?
- What is the position of CHP installations when CO₂ prices are higher?
- What is the position if the share of renewable energy rises faster than predicted?
- What is the position if supply and demand on the electricity market are more balanced, and a mark-up⁸ is applied to the electricity price again?

3.1 Approach

Models

The position of CHP installations is described by an analysis using two models.

A **simulation model** of the NW-European market is used first.

This model calculates which production units are used *for each hour in a year*. The power stations in the Netherlands are modelled individually in this model, including the larger CHP units. The modelling distinguishes between must-run, partial spark-spread and flexible units, as described in Section 2.2.

The modelling produces the electricity prices and shows how much the CHP installations are used and what the variable costs and benefits are on an hourly basis. It is assumed that the CHP units are present in the market, and that must-runs operate continuously. The simulation model is described in more detail in Annex F. Second, the position of CHP installations is calculated if the required investments are also taken into account. This is done with a **cost-effectiveness model**, which calculates the financial gap for each CHP installation based on the output from the simulation model (electricity prices, heat production, electricity production, start/stop costs), and the required investments.

The results are clustered according to five types of CHP installation: STEG (large/small), gas turbine (large/small) and gas engine. Annex H describes the cost-effectiveness model in more detail together with the

⁸ The 'mark-up' is a possible increase in the electricity price on the market if there are shortages.

basic assumptions used in it.

The modelling does not take account of the so-called **heat discount**. This is a discount that can be given on the price of heat supplied by CHP, and represents possible additional risks of CHP heat in comparison with heat produced from a boiler. The discount is not included because there is little objective material available about the amount of it.

Assumptions for the baseline scenario

The assumption for the baseline scenario is that the fuel and CO₂ prices will change in accordance with the 'new policies' scenario of the IEA's World Energy Outlook 2013. This scenario assumes broad political support for an active climate policy and the implementation of plans to reduce greenhouse gas emissions, including plans that have not yet been put in place, but must still be developed. This scenario can be seen as the IEA baseline scenario. The assumptions for the changes in the renewable energy production capacity are based on the agreements in the SER Energy Agreement. The information on changes in renewable energy in other countries is taken from forecasts of the European transmission system operators' organisation, ENTSO-E. All of this is summarised in Table 3 which also gives the values for 2012 and 2030. The assumptions on which this scenario is based are described in more detail in Annex E.

Table 3 Assumptions for the 2020 and 2030 baseline scenarios

			2012	2020	2030
Prices	Gas	€/GJ	8.5	8.7	9.0
	Coal	€/GJ	2.6	2.8	2.9
	CO ₂	€/t CO ₂	8.0	15	24
Installed capacity renewable energy in the Netherlands	Solar	MW	365	4 000	8 000
	Wind	MW	2 391	8 050	12 000

Required investments

Many CHP installations require investments in revamp/large-scale maintenance. An additional factor is that, from 2016/2017, CHP installations must also comply with stricter NO_x emission requirements. The typical costs of these two factors are estimated.

Regular revamp /large-scale maintenance

The revamp/large-scale maintenance costs are a major cost item. Many CHP installations have a lifetime of 10-20 years and require investment for large-scale maintenance. An estimate for this has been taken from Jacobs Consultancy (2009)⁹, after review with contacts in the market.

⁹ Techno-Economische Parameters, MEP/SDE CHP 2008, Jacobs Consultancy, 2009

This amounts to 25% of the initial investment¹⁰. This value is used in all cost-effectiveness calculations. As this is an important factor for the cost-effectiveness of installations, the cost-effectiveness is also calculated for higher and lower values (0.15 and 35 respectively). This is shown for the various scenarios in Annex J.

Investments to comply with NO_x-emission requirements

From 1 January 2016/1 January 2017 smaller CHP installations must comply with stricter NO_x-emission requirements¹¹, which have been incorporated into the Activities Decree. The costs of compliance for existing installations have been taken from a study carried out by the ECN¹². Investments are in the order of ca € 30-120/kWe, and there are also variable costs of around € 0.9/MWe/hour for NO_x. Annex D provides further information about the NO_x emission requirements under the Activities Decree and technical measures which can be used to achieve them.

3.2 Electricity market in 2020

On the basis of these data, the simulation model of the North-West European market shows how the electricity market in the Netherlands will develop. Table 4 compares the calculated shares in production in 2012 and 2020¹³. Figure 5 shows installed capacity and operating hours.

Table 4 Composition of electricity production in 2012 and 2020 (modelled), in TWh

	2012	2020
Solar	0	3
Wind	4	13
Nuclear	3	2
Coal	23	23
Gas	1	1
Other gas (including furnace gas)	3	3
Other (including biomass)	8	7
CHP	31 (42%)	20 (28%)

¹⁰ Market consultation indicated that typical revamp investments for gas turbines may be higher, in the order of 35%. 25% has been used overall to ensure the consistency of the model.

¹¹ These are the installations that were covered by the BEMS (Besluit Emissies Middelgrote Stookinstallaties [*Emission Requirements (Medium-Sized Combustion Installations) Decree*]), and are not covered by the Activities Decree.

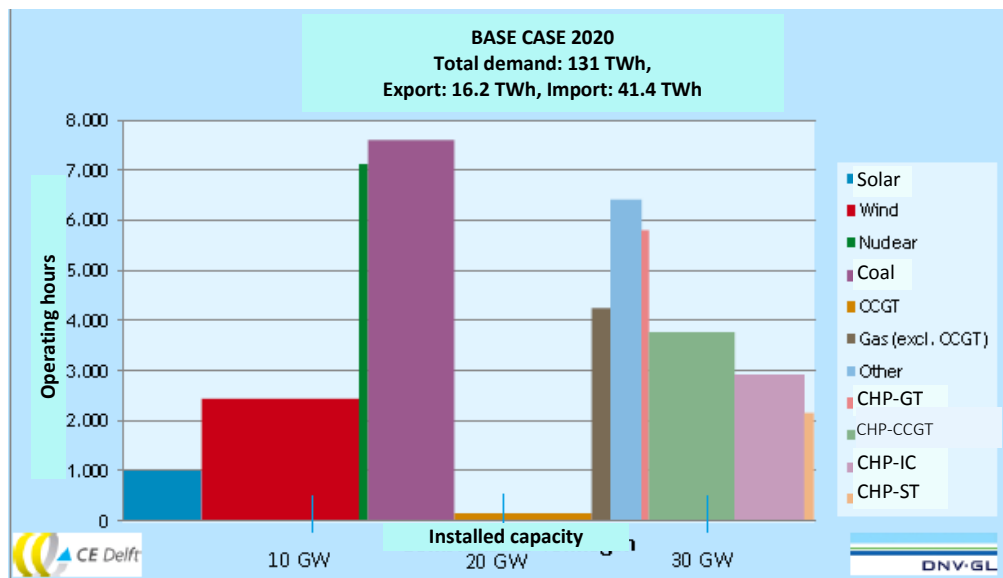
¹² Effects of the abolition of NO_x emission trading, ECN, 2012

<http://www.ecn.nl/docs/library/report/2012/n12015.pdf>.

¹³ The calculated production differs in a number of respects from the actual composition of electricity production in 2012. According to Statistics Netherlands, the total production of gas-fired power stations in 2012 was 54 TWh, which is substantially higher than the value of 32 TWh modelled here.

<http://statline.cbs.nl/StatWeb/publication/?DM=SLNL&PA=80030NED&D1=1&D2=a&D3=0,2-6,11&D4=14&HDR=T,G1&STB=G3,G2&VW=T> (Statistics Netherlands Statline, 2014).

Figure 5 Electricity market in 2020 – baseline scenario



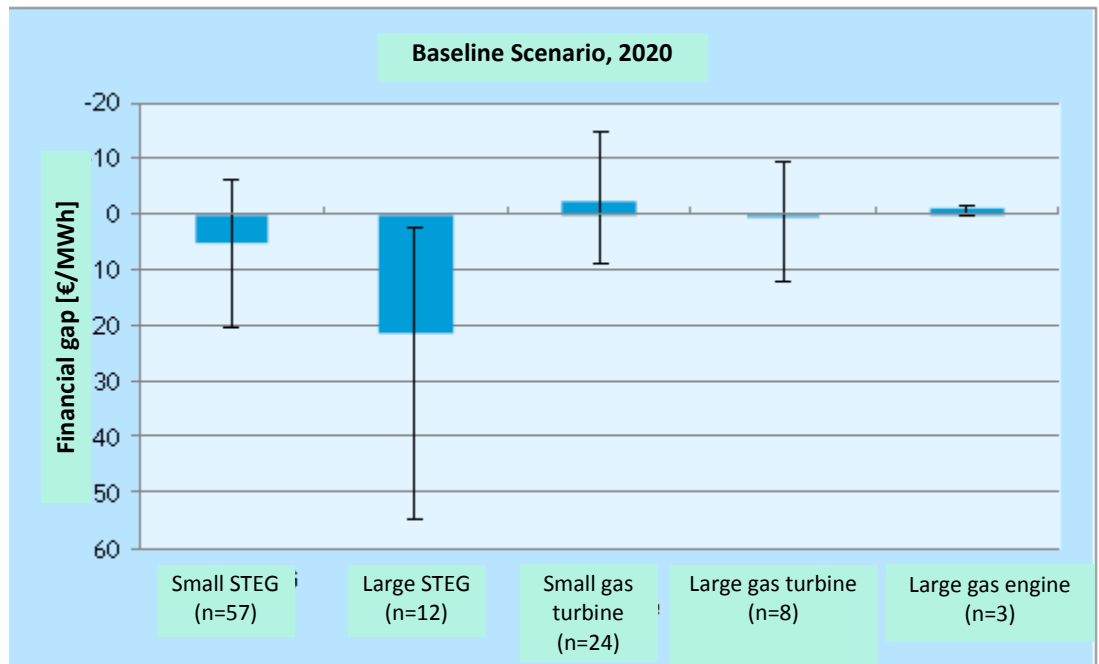
The market situation in around 2020 is characterised by a significantly larger amount of wind and solar (up from 6% to 24%), a small rise in the electricity demand and a consistent supply of cheap electricity from abroad and coal-fired power stations. In this market prices are low, with an average of € 51.7/MWh. The market share of gas-fired power stations, including CHP, is under great pressure. The reasons for this are given in Annex H (the electricity market in the scenarios).

3.3 Market position of CHP in 2020

The simulation shows the position under these market conditions on the basis of variable costs and benefits. The results of this are given in Annex I. This shows that the variable costs of must-run CHP installations are almost the same as the variable income. However flexible CHP installations do operate at a profit on a variable costs/benefits basis.

Figure 6 shows the financial gap of CHP installations in 2020. The financial gap is the amount required to make operation cost-effective, taking account of the fixed costs, including capital costs. A ‘positive’ financial gap means that the investment is not cost-effective, a ‘negative’ financial gap means that it is cost-effective. The numbers of installations per category are shown at the bottom of Figure 6. Chapter 5 examines the cost-effectiveness of must-run and flexible CHP installations in more detail.

Figure 6 Financial gap of CHP installations in 2020. The figure shows the financial gap and the bandwidth of the various installations¹⁴



Most CHP installations are in an unfavourable position in 2020, with a financial gap > 0. The performance differs considerably from one CHP to another, depending on factors such as flexibility, number of operating hours, age and efficiency. The figure above therefore includes error bars, which show the distribution of individual CHP installations.

Almost all large **STEGs** have a financial gap and as STEGs account for almost 50% of total production capacity, this has a major impact on overall cost-effectiveness.

Gas engines perform better relatively speaking. They are able to operate flexibly and so perform better on the electricity market. Gas turbines are in a better position than STEGs because they produce more heat and less electricity¹⁵.

The installations which are not cost-effective have an average financial gap of € 7.9/MWh. The average financial gap of the industrial CHP installations is € 3.2/MWh. The gas engines in greenhouse horticulture have a financial gap of - € 1.6/MWh and are therefore just about cost-effective. The total financial gap for the non-cost-effective CHP installations is € 131 million/year.

¹⁴ For small STEGs this is 3.06 GWe capacity, for large STEGs 0.45 GWe capacity, for small gas turbines 0.52 GWe, for large gas turbines 0.22 GWe and for gas engines 3.62 GWe.

¹⁵ In this analysis gas turbines perform more or less comparably to gas engines. This differs from the calculations of Cogen Nederland (Cogen Nederland, 2013) and ECN (ECN, 2008) in which gas turbines have a larger financial gap than gas engines. The differences could be due to the gas turbine efficiencies used (in this study 32%, in other studies 28%). A second factor is that this study uses an investment of 25% for revamp of GT installations, which may be on the low side.

The unfavourable market position of CHP installations can be explained by the market conditions in 2020. The electricity prices are relatively low, at € 51.7/MWh, so CHP installations earn relatively little from the electricity they produce. As a result, the variable income (from heat and electricity produced) is only just above the variable costs (fuels, CO₂ certificates) and they do not adequately recover their investments.

Annex J examines this in more detail, showing how many installations of each CHP type have a particular financial gap. An important factor for the financial gap is how much is invested in revamp. A sensitivity analysis also shows the effect at a higher and lower percentage.

At an investment of 35%, gas engines in horticulture are not cost-effective either.

3.4 Estimate of the CHP capacity shut down

Under these conditions, 53% of the installed CHP capacity will have a financial gap in 2020. This is equivalent to 4 600 MWe, and affects almost 80% of the installed capacity in industry and the built environment. If these installations are shut down 40.3 PJ heat and 56.9 PJ electricity will be lost.

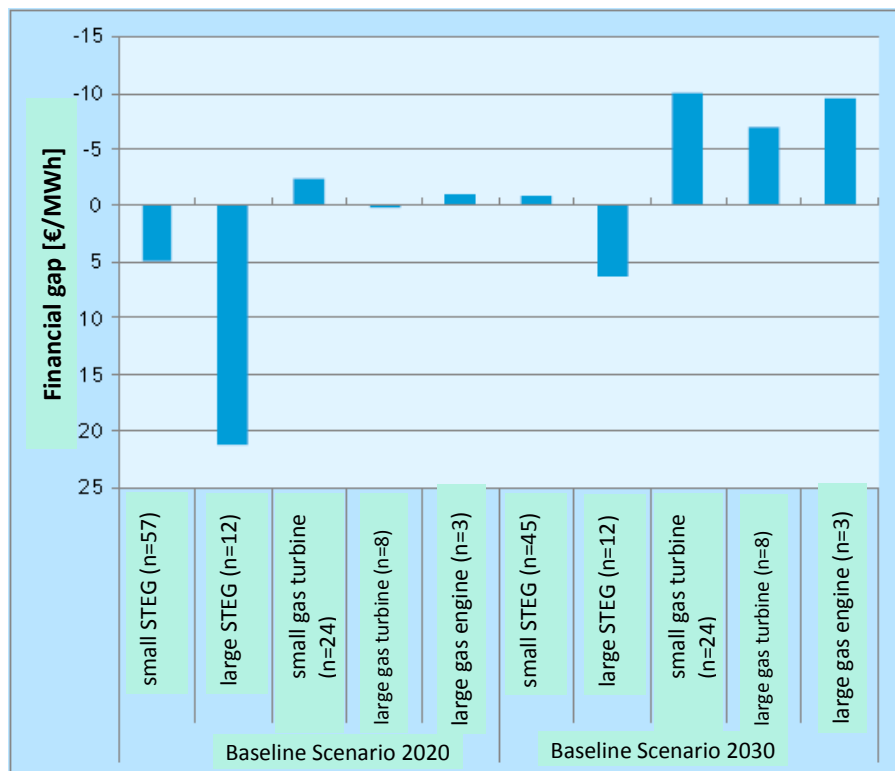
If the CHP installations in greenhouse horticulture were also shut down, another 3 000 MWe would be lost. In total, this amounts to 7 600 MWe, or 87% of the CHP capacity and an electricity loss of 70.2 PJ heat and 87.4 PJ electricity.

3.5 Market position of CHP in 2030

Figure 7 shows the financial gap of CHP installations in 2030 in comparison with 2020. These calculations are based on the CHP capacity in 2014, under the baseline scenario (Section 3.1). It should be noted here that a large amount of the CHP capacity may have been shut down by then. It follows from this that the financial position of CHP installations in 2030 is substantially better than in 2020, with the exception of the large STEGs, which still have a financial gap.

Chapter 5 examines the position of flexible and must-run CHP installations in the various scenarios in more depth.

Figure 7 Financial gap of CHP installations in 2030 in comparison with 2020



A major cause of this development is the fall in imports from Germany as a result of the decommissioning of nuclear and coal (lignite) power stations. Growth in renewable capacity between 2020 and 2030 is also likely to be limited, and is counterbalanced by the growing demand for electricity. This results in a rise in the relative electricity price (the absolute electricity price rises due to higher fuel and CO₂ prices). Overall, the electricity price rises more between 2020 and 2030 than the assumed increase in the gas price (from Table 3).

Annex H shows the resulting profile of the electricity market in 2030, with the residual supply curve and the price curve. The electricity prices are significantly higher than in the 2020 scenario, which substantially improves the income of CHP installations.

3.6 Position of CHP in 2030 in other scenarios

The future development of the energy market up to 2030 is surrounded by uncertainty and it may not develop in the way assumed in the baseline scenario. Important factors are:

- fuel and CO₂ prices (which determine the costs/benefits of CHP, and its competitive position in relation to other production units);
- installed capacity of renewable energy sources (which determines the need for flexibility);
- the electricity price margins - the mark-up.

Mark-up

The mark-up is the difference between the price the market is prepared to pay and the (estimated) marginal production costs of the last power station in the ranking needed to meet demand. It is likely to be applied when the supply and demand in the market are relatively balanced, as in the period 2000-2006, when mark-ups were applied to electricity prices above € 65/MWh. The projected market position of CHP installations in 2030 if these mark-ups are applied has been modelled on the basis of APX data for mark-ups in the period 2000-2006. An average annual mark-up of € 8/MWh has been factored in to analysis with the cost-effectiveness model, in line with the situation in 2000-2006. It can be argued that if the electricity market becomes more balanced, electricity prices may well be subject to a mark-up again. An uncertain factor in this is the effect of interconnection with other countries (which will be greater in 2030 than in around 2005). Depending on the amount of the mark-up and the number of hours on which it is charged, this may significantly improve cost-effectiveness.

See also: http://europa.eu/rapid/press-release_IP-07-522_nl.htm (EU (Rapid), 2007)

Scenarios

The position of the CHP production capacity has therefore also been studied for four other scenarios in addition to the baseline scenario:

- *'High CO₂ prices'*: a scenario with a global climate policy and high CO₂ prices. This is based on the WEO 2013 scenario '450 ppm'.
The higher CO₂ price means that electricity produced from gas may even be a little cheaper than that produced from coal.
- *'Low CO₂ prices'*: a scenario based on 'business as usual', without additional energy and climate policy. This is based on the WEO 2013 scenario: current policies.
- *'High renewable'*; this is based on accelerated growth of renewable energy production, which assumes additional growth of wind and solar in the Netherlands and other countries.
- *'Mark-up'*; this scenario assumes a more balanced electricity production market, as in the period 2000-2006, in which the demand side may be prepared to pay prices higher than the basic marginal production costs. This is based on a margin of € 8/MWh. This is an indicative figure, intended only to illustrate a possible effect.

The basic assumptions for the scenarios are described in more detail in Annex E.

The main parameters for the four scenarios are summarised in Table 5.

Table 5 Basic assumptions in the 2030 scenarios

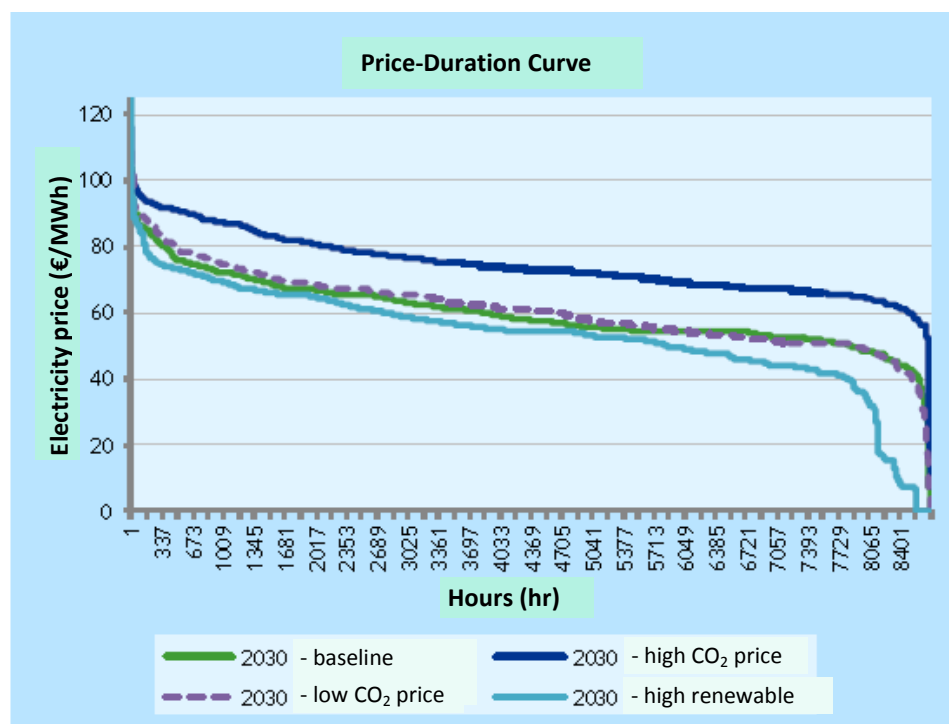
Scenario	Unit	Base scenario	High CO ₂ prices	Low CO ₂ prices	High renewable	'Mark-up'
CO ₂ price	€/t CO ₂	25	<u>71</u>	<u>19</u>	25	25
Amount of wind and solar in the Netherlands	GW installed capacity	20	20	20	<u>30</u>	20
Amount of wind and solar in surrounding countries	Ditto	cf. Entso-E, 'best estimate'	cf. baseline	cf. baseline	<u>+33% in relation to baseline scenario</u>	cf. baseline
Mark-up	€/MWh	-	-	-	-	<u>8</u>

The figures are calculated in the same way as in the baseline scenario: the total market in North-West Europe including the CHP installations is simulated first. Then the results of the simulation, together with typical investment amounts are entered into the cost-effectiveness model.

Figure 8 shows the price profiles for the various scenarios. It is clear that the electricity prices are higher in the scenario with high CO₂ prices (450 ppm). The high renewable scenario has low prices <€ 20/MWh¹⁶ for ca 600 hours.

¹⁶ The number of hours with 'surplus' electricity from wind and solar is limited because not only the share of wind and solar, but also the peak demand, will have increased in 2030. The fact that the simultaneous nature of wind production, solar production and the level of demand has also been included in the analysis (e.g. on a sunny summer day, PV electricity production coincides with peak daytime demand and wind production may be relatively low) also plays a part.

Figure 8 Price-duration curve per scenario



Annex H develops the various scenarios for the electricity production capacity (profile of the electricity market, residual demand-duration curve and electricity price).

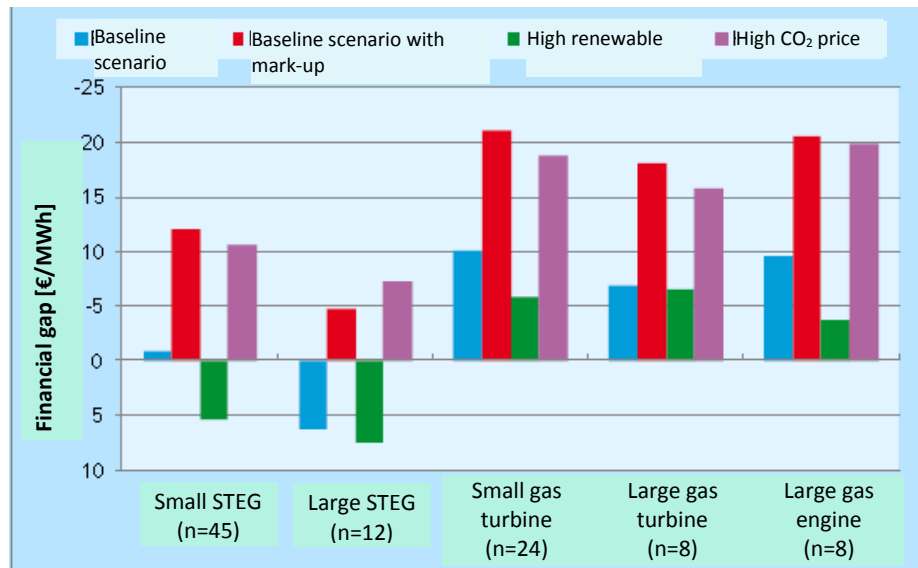
On the basis of this, Annex I gives the variable costs/benefits of CHP installations in the different scenarios. According to this CHP installations perform considerably better in the high CO₂ price scenario, when the variable benefits are 13% higher than the variable costs. Another striking fact is that in the 'high renewable' scenario, must-run CHP performs considerably worse, as the variable costs are higher than the variable benefits.

Results

Results are summarised in Figure 9, which shows that the position of CHP installations is markedly better under the scenario with a high CO₂ price and a mark-up, when most CHP installations are cost-effective. The scenarios high renewable and low CO₂ prices differ little from the baseline scenario.

Annex J shows the results, giving the financial gap per type of CHP for the individual CHP installations. It also shows the effect of a higher or lower percentage of investment in renovation.

Figure 9 Cost-effectiveness of existing CHP facilities under different scenarios in 2030



3.6.1 Position of CHP at high CO₂ prices

When CO₂ prices are high CHP installations perform very well. All types of CHP installation have a negative financial gap and therefore operate cost-effectively. This is because the high CO₂ prices (€ 71/t CO₂) result in substantially higher electricity prices.

The off-peak price is almost the same as the peak price as the price difference between coal- and gas-fired power stations is minimal. The CHP installations therefore earn more from the production of electricity. A second factor is that the heat produced by the CHP installations also has a higher market value, because the price of heat is raised by the higher cost of CO₂. The higher CO₂ price has the opposite effect of pushing up the costs of CHP installations due to the higher cost of the CO₂ produced. However, this effect is outweighed by the growth in the benefits¹⁷. This can be explained by the fact that integrated generation of electricity and heat with CHP is more efficient and lower in CO₂ than separate generation. This makes the net CO₂ emissions lower than competing options and a higher CO₂ price provides an increasing financial advantage.

3.6.2 Position of CHP with a high level of renewable energy

When the level of renewable energy is high, CHP installations perform less well than in the baseline scenario. The small and large STEGs have a financial gap, although the gas turbines and gas engines are cost-effective. This is because the high level of renewable energy leads to lower electricity prices. The prices are several €/MWh lower than in the baseline scenario for the whole year. There are also ca 600 hours of surplus production, in which the price falls below € 20/MWh. This means that CHP installations earn less from the production of electricity. The effect is the

¹⁷ Another effect is that the gas prices in this scenario are than in the basic scenario. This also has a positive effect on the performance of CHP installations. However, simulation calculations show that this effect is limited.

strongest with must-run CHP installations. These also have to operate at times when prices are very low, and losses then mount up. Other fossil production units also operate unfavourably in this scenario as a result of the low prices.

3.6.3 Position of CHP when the market balance is restored and there is a mark-up

The mark-up has a very positive effect on the performance of CHP installations. All types of installation have a negative financial gap.

4 Impact of shutting down CHPs on energy use and CO₂ emissions

The model calculations show that in 2020 53% of CHP installations will have a financial gap. If this CHP capacity is shut down, heat and electricity will be produced by other installations. Given the scale of the CHP capacity, this could have a major impact on energy use and CO₂ emissions. The questions we are focusing on here are:

- Which types of production unit are expected to take over the production of electricity and heat in the absence of CHP?
- What impact will that have on energy use?
- What is the expected impact on CO₂ emissions?
- What is the expected impact on emissions of other forms of air pollution?

Calculations have been made for the shutdown of the CHP units which will be unprofitable in 2020 according to the cost-effectiveness calculation - 53% of capacity.¹⁸ Calculations were also made for a situation in which there are no longer any CHP installations in greenhouse horticulture either, accounting for 35% of capacity.¹⁹ This is because, according to these calculations, the cost-effectiveness of these CHP installations is very marginal.

A significant part of CHP capacity was shut down in the period leading up to 1 January 2014 and this will already have affected CO₂ emissions and primary energy use. This is not factored into the calculations.

4.1 Which installations will take over the production of heat and electricity in the absence of CHP?

The impact of shutting down CHP installations will depend on which installations take over the lost electricity and heat production.

Substitute heat production

For heat, the most obvious scenario is that CHP heat will be taken over by gas-fired boilers. This development can already be seen in the market. There are alternatives to heat production from gas-fired boilers, which are discussed in Chapter 6. However, these alternatives are subject to constraints: the potential of some options is limited (e.g. production of steam from waste, or supply of steam from waste incinerators), and the costs of other options are higher (biomass, geothermal energy).

¹⁸ Loss of heat production: 40.3 PJ in 2020, 48.8 PJ in 2030; loss of electricity production: 56.9 PJ in 2020 and 69 PJ in 2030.

¹⁹ Loss of heat production: 70.2 PJ in 2020, 80.7 PJ in 2030; loss of electricity production: 87.4 PJ in 2020 and 102 PJ in 2030.

Substitute electricity production

It is less clear which substitute source will be used for electricity production. This will be determined by the market situation at the time CHP is shut down. Production can also be covered by imports.

We map the impact of substitute electricity production for three variants:

1. Replacement by the reference capacity (excluding renewable energy).
2. Replacement by coal-fired power stations.
3. Replacement by gas-fired power stations.

The first approach is that production capacity will be taken over by the average electricity production capacity, the '**reference capacity**'. In principle, this comprises both renewable and fossil energy sources. For the electricity produced by CHP installations we should look at replacement by *fossil electricity production capacity*²⁰, in other words excluding renewable sources²¹. These are also fossil units other than CHP installations. This fossil reference capacity consists primarily of coal- and gas-fired power stations. Here, the efficiency is the relationship between the amount of electricity produced and the energy content of the fuel. This is 45% in 2020, which is relatively low due to the number of older gas- and coal-fired power stations, and the same as that of new coal-fired power stations. The efficiency of the reference capacity is higher in 2020, at 51%, because older coal- and gas-fired power stations will then have been shut down.

The second and third approaches assume that electricity production can be taken over by recently built gas- and coal-fired power stations, which have efficiencies of 58% (in 2020 and 60% in 2030) and 45% respectively.²² The boiler efficiency is assumed to be 90%.

According to the simulation gas-fired power stations are unfavourably placed in the ranking. Replacement of CHP electricity by coal-fired power stations abroad therefore seems more likely. A critical factor here is whether there will be sufficient transport capacity.

The unfavourable position of CHP installations is partly a result of the growth of the amount of renewable energy used in electricity production. However, this growth itself helps to reduce the primary energy use of the total electricity production system significantly by 143 PJp in 2020 and 251 PJp in 2030 (baseline scenario).

²⁰ The approach does not take account of the amount of renewable energy in the production capacity. This is because renewable energy from sun and wind is marketed first, because of its very low marginal costs. When CHP is shut down, the amount of energy produced from wind and sun will therefore not increase. This approach is in line with the protocol Monitoring Energiebesparing (ECN, 2001)²⁰ and more recently the Handreiking Uniforme Maatlat (SQ, 2012)²⁰, and the results of the simulations of the energy market in North-West Europe carried out for this study. They show that renewable energy is always used at full capacity.

²¹ In the baseline scenario the production of renewable electricity is 23.7 TWh higher in 2020 than in 2012. Based on the fossil reference capacity, this results in a primary energy use saving of 143 PJp. In the baseline scenario for 2030 the production of renewable energy grows by 35.5 TWh, leading to a 251 PJp saving on primary (fossil) energy use.

²² Other assumptions: boiler efficiency: 90%.

4.2 Impact on primary energy use

2020

If 53% of the production capacity is shut down and replaced by the fossil reference capacity, the primary fuel consumption will rise by 40 PJp. If 87% of the capacity is shut down, it will rise even further to 68 PJp²³. It will rise far less if electricity production is replaced by new gas-fired power stations than if it is replaced by new coal-fired power stations. The results are summarised in Table 6²⁴.

The underlying reason for this rise is that, in the absence of CHP, heat and electricity will be generated separately, and less efficiently. The effect is greatest for coal-fired power stations, as they produce electricity at relatively low efficiency.

The calculation is based on the calculated number of operating hours of CHP installations in 2020. This is lower than the number of operating hours in 2012. If it is based on the number of operating hours for 2012 the impact on primary energy use is greater²⁵.

2030

If production is replaced by the fossil reference capacity, the primary energy use will rise by 30 PJp if 53% of the production facilities is shut down and 51 PJp if 87% is shut down. The rise in 2030 is lower than in 2020 as the fossil capacity will then be more efficient.

The impact of replacement by coal-fired power stations is somewhat higher than in 2020. This is because, in the simulation modelling, CHP installations will operate for more hours in 2030 when the market conditions are more favourable. This means that more CHP production will then be lost.

Table 6 Impact of shutting down CHP installations on primary energy use (PJp)

Substitute electricity produced by:	53% shut-down (excl. CHP installations in greenhouse horticulture)		87% shut-down (incl. CHP installations in greenhouse horticulture)	
	2020	2030	2020	2030
Fossil reference capacity (excl. renewable energy)	40	30	68	51
Gas-fired power stations	11	10	24	22
Coal-fired power stations	40	48	68	78

The assumptions and results of the calculations are examined in Annex K.

²³ For comparison, the total primary energy use of the CHP production capacity in 2020 is 263 PJp.

²⁴ A calculation of replacement by the reference capacity including renewable energy produces a rise of 11 PJp in 2020 and a fall of 11 PJp in 2030. This is due to the rise in renewable production capacity.

²⁵ Based on replacement by the fossil reference capacity: in 2020, 53 PJp with a 53% shut-down and 86 PJp with an 87% shut down of CHP capacity. In 2030 the figures are 34 and 56 PJp respectively.

4.3 Impact on final energy use

Final energy use is the use of electricity and heat by end users. The Netherlands has formulated its energy saving targets under the Energy Efficiency Directive in these terms. The shut-down of CHP capacity will not affect this because end use by customers is not affected by the method of generating heat and electricity.

4.4 Impact on CO₂ emissions

2020

The impact on CO₂ emissions is also highly dependent on the type of installations that replace CHP production of electricity. If it is replaced by new gas-fired power stations it is 0.6 Mt, if it is replaced by coal the emissions increase by 7.6 Mt. If the installations in greenhouse horticulture are also shut down, the figures are proportionally higher. This is because the CO₂ emissions will be higher if electricity production is replaced by coal as coal has a higher CO₂ emission factor than gas. Substitute heat and electricity production will also be less efficient than CHP. If we assume that the CHP installations in greenhouse horticulture will also be shut down (phase-out of 87%), the figures are higher, at 11.6 Mt.²⁶

Here too, the calculation was based on the calculated number of operating hours in 2020. If it is based on the higher number of operating hours in 2012, the increase in CO₂ emissions is higher²⁷.

2030

Assuming replacement by gas, the increase in CO₂ emissions is comparable to that in 2020. Here too, emissions will increase far more, by 9.2 Mt, if CHP is replaced by coal. As in 2020 the figures are proportionally higher if we also assume that CHP installations in greenhouse horticulture will be shut down. These amount to 13.4 Mt.

²⁶ If the calculation includes the reference capacity including renewable energy, the increase in CO₂-emissions is 2.4 Mt in 2020 and 1.5 Mt in 2030. The reduction in 2030 in comparison with 2020 is a result of the increase in the share of renewable production capacity.

²⁷ Based on the number of operating hours in 2012, CO₂ emissions in 2020 will increase by 0.9 Mt (53% scenario) and 1.2 Mt (87% scenario) if replaced by gas. If replaced by coal the increase will be 10.2 Mt and 14.6 Mt respectively. The figures for 2030 are 0.6 Mt and 0.8 Mt for gas, and 10.4 Mt and 14.7 Mt for replacement by coal.

The results are summarised in Table 7.

Table 7 Impact of shutting down CHP installations on CO₂ emissions

Substitute electricity produced by:	53% shut-down (excl. CHP installations in greenhouse horticulture)		87% shut-down (including CHP installations in greenhouse horticulture)	
	2020	2030	2020	2030
Gas-fired power stations	0.6	0.5	0.9	0.7
Coal-fired power stations	7.6	9.2	11.6	13.4

EU ETS

Many of the CHP installations are covered by the European Emission Trading System for greenhouse gases, the EU ETS.

To be part of the system the establishment in which the installations are located must have a total thermal input of more than 20 MW. Most industrial capacity falls into this category. Smaller installations in industry and the built environment may fall outside the EU ETS.

The majority of installations in greenhouse horticulture do not fall directly under the EU ETS; but are subject to a ceiling for 2020 within the CO₂ sector system for greenhouse horticulture. They buy the right to exceed the ceiling in the form of EU ETS certificates. In this sense there is thus a connection between CO₂ emissions and the EU ETS for greenhouse horticulture also.

Substitute emissions (electricity and heat) will mainly come from installations which fall within the EU ETS. One exception is boilers in smaller industrial companies. Shutting down CHP installations in the built environment may also lead to an increase in CO₂ emissions outside the EU ETS.

In this sense, EU ETS emissions will increase below the EU ETS ceiling. Assuming there is a functioning EU ETS system this would not result in an increase in emissions in Europe as a whole.

4.5 Impact on other emissions

Shutting down CHP installations will also have an impact on other emissions to air. Here, we examine the emissions of NO_x, particulates and SO₂. The impact depends on the type of installation that replaces CHP production of heat and electricity. We also assume that there are statutory emission requirements under the Activities Decree. Combustion plants (CHP installations and others) must comply with these requirements from 2016/2017. They are summarised in Annex D. The effect is determined primarily by the extent of the emissions from substitute installations. A second factor is that separate generation will often be less efficient, leading to a greater use of fuels and thus higher emissions. We map the expected impact on emissions in qualitative terms.

Particulates and SO₂

Particulates and SO₂ will increase if CHP electricity production is taken over by coal-fired power stations²⁸, as coal-fired power stations emit more particulates and SO₂ than gas-fired power stations. Particulate and SO₂ emissions from gas-fired CHP units are negligible and there will be no net increase in emissions.

NO_x

It is more difficult to establish what the net effect will be for NO_x. In general, the substitute heat production will probably be coupled with lower NO_x emissions, as gas-fired steam boilers are subject to a stricter

²⁸ There is therefore likely to be an increase in emissions from coal-fired power stations abroad.

NO_x emission requirement (70 mg/m³) than CHP installations (100-340 mg/m³ for gas engines, 50-140 mg/m³ for gas turbines). On the electricity side, emissions will scarcely be reduced at all if production is taken over by gas-fired power stations, as large gas-fired power stations must comply with virtually the same NO_x emissions as smaller CHP installations (from 1 January 2017).

To establish the impact of replacement by coal-fired units more detailed analysis is required to determine the net effect, taking account also of the lower generating efficiency.

5 Position of flexible CHP in the energy market in 2030

In the energy market in 2020/2030 the installed renewable electricity production capacity will be considerably higher. The number of hours will increase and there will be a surplus of electricity production (characterised by low electricity prices) and shortages (characterised by high electricity prices).

In this chapter we examine the future market position of flexible and must-run CHP installations in industry and greenhouse horticulture, technical possibilities for converting must-run CHP installations, and make an indicative comparison of the economic position of CHP with alternative flexibility options. In the analysis we use simulation modelling, which shows the frequency of surpluses and shortages in the scenarios. Chapter 3 describes how flexible and must-run CHP installations are defined in the modelling.

Specific questions for improved flexibility are:

- How does the efficiency of flexible CHP installations compare with that of 'must-run' CHP installations?
- What are the options and costs for converting must-run CHP installations to flexible units?
- What is the position of flexible CHP for covering electricity production shortages?
- What is the position of flexible CHP with Power-to-Heat for covering surpluses of electricity production?
- How is flexibility of CHP installations rewarded in the market and regulations and what are the impediments?

5.1 Efficiency of flexible v. must-run CHP installations

The results show that flexible units generally perform better than 'must-run' units. To illustrate this, Figure 10 shows the financial gap of CHP installations in industry and greenhouse horticulture²⁹ based on the baseline scenario before 2020. The figure shows that flexible CHP installations are generally more efficient than must-run units. This is consistent with the results of the simulation modelling in which flexible units also consistently perform better.

²⁹ Numbers of CHP units per category:

	Small STEG	Large STEG	Small Gas turbines	Large Gas turbines	Gas engine
Flexible	39	0	25	5	3 000
Must-run	9	6	0	3	19

Figure 10 Financial gap of CHP installations in industry and greenhouse horticulture in 2020

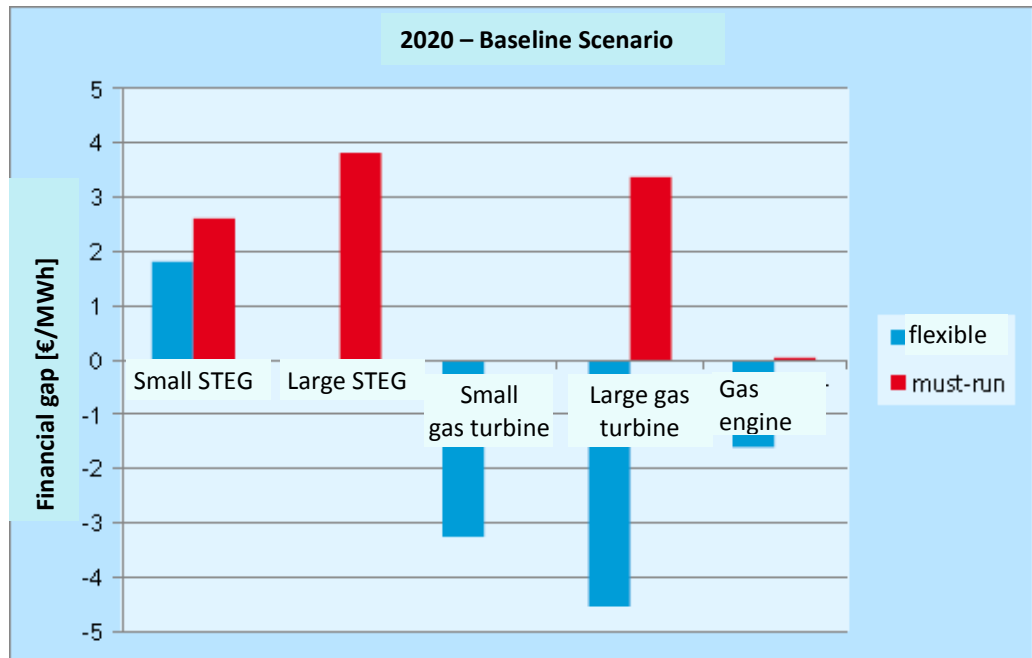
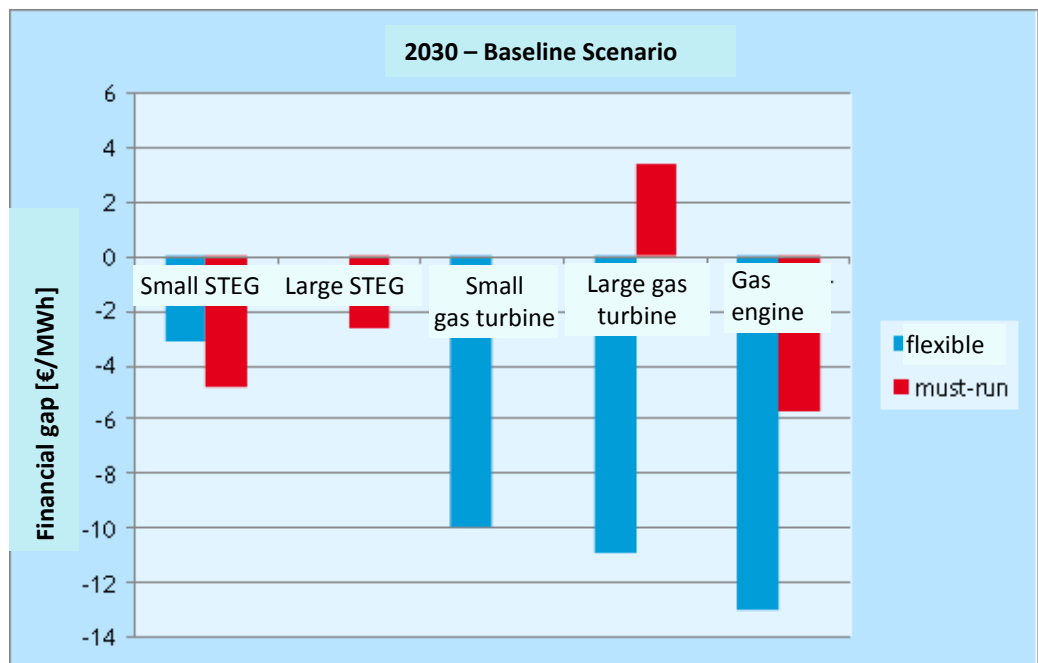


Figure 11 illustrates the efficiency of flexible and must-run CHP installations in 2030 under the baseline scenario.

Figure 11 Position of must-run and flexible CHP installations in 2030 under the baseline scenario



The figure shows that in 2030 the economic position has improved for all types, and the flexible CHP installations are in a better economic position than the must-run installations. The small STEGs are an exception. This is probably because they produce a larger amount of electricity.

Annex J.6 gives the figures for the scenarios with a high level of renewable energy, a mark-up and a high CO₂ price, which show that the gap between flexible and must-run CHP installations is greater in a scenario with a high level of renewable energy. The position of the must-run installations is somewhat better in the mark-up and high CO₂ price scenarios than in the baseline scenario.

5.2 Conversion of must-run to flexible CHP

Technical possibilities for converting CHP installations to flexible operation are described in Table 2 of Chapter 2. The main options for adapting the CHP installation itself are adding a separate boiler and modifying the flue gas boiler (by fitting a supplementary heating burner and combustion air blower). Another route is to add a heat buffer, so that the connection between heat production and demand can be broken. This is only possible for low-temperature applications.

There is a total of 1 560 MWe 'must-run' capacity in industry. The typical cost of converting waste heat boilers is € 30-40/kW, but they cannot always be converted. The total cost of adding boilers is around € 100-150/kW, which amounts to around € 75-150 million for the whole of the must-run capacity. This also entails operational costs for keeping the boiler hot, amounting to around € 5 million a year in total.

Converting a CHP installation to flexible operation does result in slightly higher primary energy use than in must-run operation³⁰.

5.3 Position of CHP in covering shortages

In the simulation modelling we looked at three different options for covering temporary shortages (periods in which there is hardly any renewable electricity production) in the electricity market: pumped storage (storage in reservoirs in Norway, via interconnection), demand side management and peak load gas turbines (without heat use). The following basic assumptions were used for this:

- demand side management: the shutting down of (industrial) consumption in return for an average payment of € 125/MWh³¹;
- a peak load gas turbine: these can be started up quickly to supply electricity;
- pumped storage/interconnection: the use of pumped storage capacity in Norway by laying an additional cable between the Netherlands and Norway.

The simulation modelling shows that shortages are relatively rare. The number of hours in which prices >€ 100/MWh is negligible, even in the scenario 'high renewable' (Annex F). As a result, the flexibility options peak load gas turbines and demand-side management are not used in the

³⁰ A 'back of the envelope' calculation: in the modelling flexible CHP installations in 2020 run for an average of ca 5 500 hours. This means ca 30% separate generation, and a corresponding increase in primary energy use and emissions.

³¹ Derived from: ENTSO-E, 2007, and: CE Delft, 2012, MKBA Intelligente netten

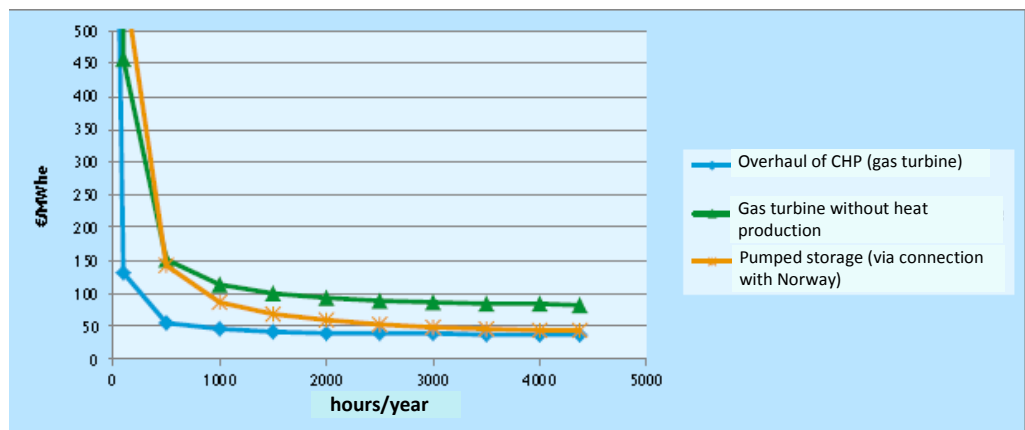
simulation, except for a limited number of hours in the ‘high renewable’ scenario. However, pumped storage via interconnection is used when the prices are sufficiently higher in the Netherlands than in Norway. The amount involved is 0.08 TWh in the baseline scenario and 0.4 TWh in the high renewable scenario. Flexible CHP is used on a large scale and thus appears to be cheaper than these alternative options on the basis of variable costs/benefits.

The simulation also shows that flexible CHP is more likely to be used than gas-fired power stations. As a result flexible CHP installations are operated for considerably more hours than gas-fired power stations: flex-CHP operates for 5 500 hours in the 2020 baseline scenario, and 6 500 hours in the 2030 baseline scenario. For comparison: gas-fired power stations operate for 150 and 1 900 hours respectively in these two years.

Total costs over the lifetime

Even if the investment costs are taken into account, flexible CHP is a cheaper option than peak load gas turbines (without heat recovery). However, pumped storage (via interconnection with Norway) is a competitive option. To illustrate this, Figure 12 shows the ‘levelised costs’ (total of investments and operating costs, expressed in €/MWh) of these three options³². The figure shows which electricity prices are needed to be able to operate the option cost-effectively. For pumped storage only the income from covering shortages has been taken into account (not income from supply in times of surplus)³³.

Figure 12 ‘Levelised’ costs for options to cover shortages, depending on the number of hours for which the option is used



³² For CHP this is based on a 60-100 MW gas turbine, with an electrical efficiency of 42-46%. It is assumed that the investments required for renovation and compliance with the NOx requirements have been made. For the gas turbine, for investments in a new installation. For pumped storage the investment costs of a second interconnection link (600 MW) with Norway have been assumed. Other assumptions: gas price € 9/GJ, CO₂ price: € 0/MWh, investments: € 600 million/new cable, € 260/KW for peak load gas turbine, and € 260 for revamp of CHP gas turbine.

³³ One point to be considered is the security of pumped storage: to what extent will supply be possible in times of drought?

5.4 Position of flexible CHP in dealing with surpluses

There are two ways of using flexible CHP to respond to surpluses:

1. Shutting down electricity production.
2. Converting a surplus to heat via Power-to-Heat.

Power-to-Heat

Power-to-Heat converts electricity to heat in electric boilers. It can reach high temperatures, so both hot water and steam can be produced.

The boiler can switch from virtually no production to full capacity in 3-10 minutes and has an efficiency of 99%. Power-to-Heat is proven technology and typical investments are low. Power-to-Heat can be integrated with CHP and can also be used as a stand-alone solution for heat production.

Power-to-Heat offers opportunities for supplying heat to industry, the built environment and greenhouse horticulture and is operating commercially in Denmark and Germany, where it is linked to CHP and district heating.

Power-to-Heat is a tried and tested method and investments are relatively low. Modelling shows that PtH is cost-effective at prices of $< \text{ca } \text{€ } 40/\text{MWh}$, when it is cheaper to produce heat from electricity than from a gas-fired boiler. The economic viability of Power-to-Heat is thus determined by the number of hours for which electricity prices are below this limit.

Transport of electric steam boiler (source: VAPEC)

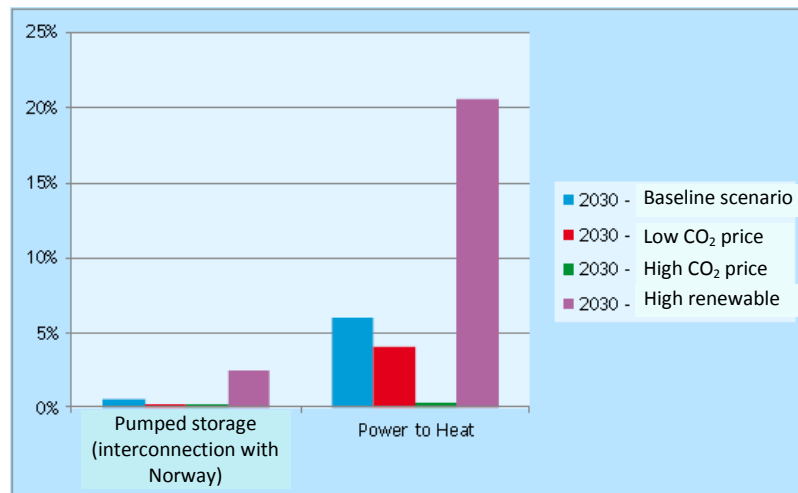


Results of the simulation model

The simulation shows that Power-to-Heat is used at prices $< \text{€ } 42/\text{MWh}$ (depending on the gas and CO_2 price). This amounts to 500 hours in the baseline scenario. In the high renewable scenario, the prices are lower and Power-to-Heat is used more often, for ca 1 600 hours.

The simulation also shows that 'pumped storage' is used to a limited extent. This is because when electricity prices are low in the Netherlands, they are often also low elsewhere and the cheap electricity from the Netherlands is then competing with cheap electricity from other countries. The results are shown in Figure 13.

Figure 13 Use of flexibility options for surpluses in simulation modelling



5.5 Current rewards for flexibility

Various markets reward flexibility:

- the futures market;
- the day-ahead market (DAM), also called the spot market;
- the intra-day market (IDM);
- the balancing market (BM).

The markets operate on different timescales: up to the day before supply, electricity is traded on the futures market, after that on the day-ahead market. Once the DAM closes, the intra-day market (IDM) offers another opportunity to trade electricity. CHP installations can play an important part in these markets. In the last phase before supply, up to an hour before supply, supply and demand capacity can be offered on the balancing market. This is a unilateral market in which TSO TenneT acts as sole buyer. TenneT works with minimum blocks of 5 MWe, which must be available throughout the year. According to TenneT hardly any CHP installations are contracted to supply balancing capacity.

The limited predictability of wind and solar energy is expected to lead to rising prices and big fluctuations on the balancing market. In addition to income for the upward adjustment reserve, income for the downward adjustment reserve will also be important. The DAM market will probably be the dominant mechanism for income from flexible capacity. But fast and flexible units will be able to generate even higher margins on the Interday Market and the Balancing Market for some of the capacity. The possibility of marketing flexible CHP capacity will improve if the purchase of this capacity is organised by month in each quarter.

5.6 Additional costs of flexibility

However, increasing the flexibility of a CHP installation can also entail additional costs for the operator. These are mainly the energy tax and fees payable to the network operator. Companies say that these additional costs can significantly undermine the cost-effectiveness of flexible CHP installations³⁴.

Energy tax

Under the Environmental Taxes Act [*Wet Belastingen Milieugrondslag*] (WBM) (National Government, 2014) CHP installations are eligible for an energy tax exemption on the gas used, *if* they achieve an electrical efficiency of more than 30%³⁵. CHP installations which increase their flexibility may fall below this limit, particularly gas turbines; STEGs generally have an efficiency far above 30% (see the figure in Annex C). If a CHP installation falls below the 30% criterion, it may be subject to a considerably higher tax rate. This provision is designed to avoid double energy tax (on the use of gas and the purchase of electricity) on installations which produce substantial amounts of electricity. Furthermore, district heating installations specifically are only eligible for a reduced gas tax rate under the WBM if at least 50% of the heat supplied comes from CHP ('residual heat') or sustainable sources (Article 59). If they fall below this limit, they are regarded as 'collective heating' and the heat supplied is subject to the first, highest tax band.

Fee to the network operator

A company with a flexibly operated CHP installation will purchase electricity from the network at times of surplus/low prices. A transport fee must be paid to the network operator³⁶ for this, which creates additional costs for the operator of the CHP installation.

³⁴ See, for example: AkzoNobel, 2014, Gas fired CHP: efficiency, flexibility or mothballing, <http://www.industriewarmte.nl/Portals/3/Sikke%20Klein%20-%20efficiency%20flexibilisering.pdf>.

³⁵ Art. 64: Exemption from tax shall be granted for the supply of natural gas and electricity used to generate electricity in an installation with an electrical efficiency of at least 30% or in an installation used to generate electricity solely by means of renewable energy sources and electricity.

³⁶ A fee of this kind is not payable for the supply of electricity from the CHP installation

6 Options for meeting the industrial heat demand efficiently and/or sustainably

This chapter examines the possible alternatives for meeting the heat demand in industry and greenhouse horticulture sustainably. To gain some idea of this, we visited five companies which are using, or planning to use, alternative technologies. We also found out about new developments from parties working to develop sustainable alternatives, such as the ISPT and the Netherlands Enterprise Agency.

This has provided an insight into the following specific questions:

- What alternatives do companies use to meet their heat demand and what experiences have they had with these?
- What potential do these alternatives offer for the Dutch industry and greenhouse horticulture sector as a whole?
- What are the typical costs of these alternatives; how do they compare with the generation of heat with CHP?
- What is the potential of other alternatives, what potential do innovative developments offer?

We visited five companies: AkzoNobel, Ammerlaan, AVEBE, Eska Graphic Board and Parenco.

The results were discussed with the feedback group (Annex A). The conversations and the discussions with the feedback group produced policy suggestions for promoting the use of alternatives, which are included in Annex L.

6.1 Alternatives used to make heat generation sustainable

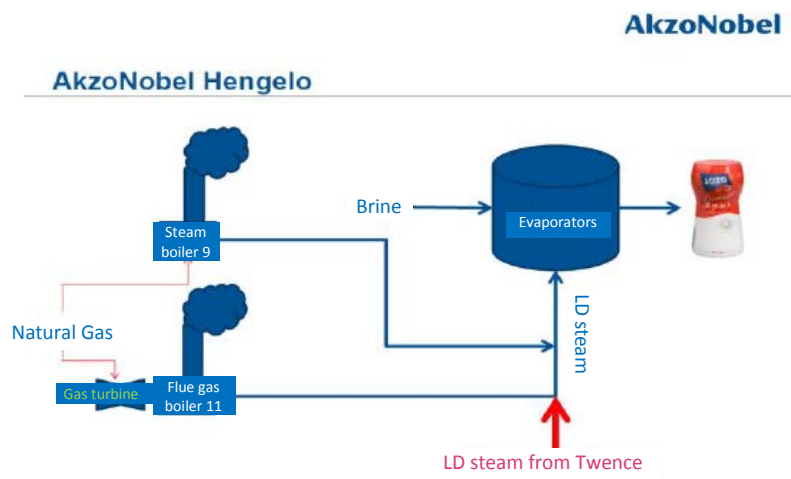
The five companies visited are working with five different methods to make their heat demand sustainable. These are: using steam from waste incineration plants, producing steam with biomass, producing steam with residue streams and geothermal energy.

A fifth route is optimising CHP installations by integrating energy streams from the process with the CHP installation.

6.1.1 Using steam from waste incineration plants

The Akzo Nobel salt plant in Hengelo uses steam from the Twence waste incineration plant. Waste incineration plants also supply steam in other industrial clusters such as the Delfzijl steam network, HVC Dordrecht - Dupont and AVR Rozenburg - Tronox. Akzo Nobel has had a positive experience with this method and it appears to be technically and economically feasible. The various waste incineration plants in the Netherlands seem to have further potential for expansion of steam supply. A critical factor in this is whether there is a customer near the waste incineration plant which has a steam demand that fits with the available steam.

Figure 14 Steam supply from Twence to AkzoNobel's salt plant in Hengelo



6.1.2 Use of industrial residue streams for steam production

Parenco and Eska Graphic Board use residue streams from processed waste paper to fuel steam generation. Parenco uses a small amount with biomass and gas in a fluidised bed oven. It has had a positive experience with this. It is tried and tested technology and works well with an efficiency of more than ca 85%. Eska Graphic Board plans to use residue streams primarily in a gasifier and to use this to generate steam. This is an innovative technology, for which the government has provided an investment subsidy.

Consequently, this seems to be an interesting route for other companies with residue streams which can be used as fuel. However, use by companies as fuel competes with other processing routes, such as processing in waste incineration plants. The potential is therefore considered to be limited.

6.1.3 Use of biomass for steam production

A third route is the use of biomass as a fuel for heat production. This is technically feasible. Akzo Nobel is using this method at its salt plant at Mariager in Denmark, and Parenco at its plant in Renkum. It can be used in a bio CHP or in a steam boiler. Experience has shown that economy is critical, as it depends on movements in the market price of biomass. The investment cost is high.

A critical point however is the availability and the movements in the cost of biomass. Biomass stocks in the Netherlands are limited and compete with other applications, and there can also be competition between different applications for imports.

Figure 15 Akzo Nobel salt plant in Mariager, Denmark. The plant has integral biomass steam generation



Biomass CHP

Existing applications

In the paper industry biomass boilers are used on a large scale to supply heat. These are generally fluidised bed ovens in which shredded biomass is burned in a fluidised sand bed with a capacity of tens of hundreds of MW_{fuel} .

The fluidised bed ovens are often designed as CHP installations with a high pressure/high temperature steam cycle with a counter pressure steam turbine.

Types of biomass used:

- fresh wood (chips) from woods, the countryside and planting stock;
- waste wood, particularly A wood and B wood;
- imported pellets.

The reference price for fresh wood is € 48/t or € 5.3/GJ. It will not be possible to obtain pruning and thinning wood for this price everywhere in the Netherlands mainly as a result of interactions on the border with Germany and Belgium. Pellets are considerably more expensive at € 140/t or € 8.5/GJ.

Process specifications and generating efficiencies

A well-designed boiler for low-temperature return condensate (50-70°C) has a boiler efficiency of up to 90% of the calorific value. By using a flue gas condenser this can be increased to 105%.

Steam parameters are limited mainly by size (economic considerations) and biomass specifications (mainly chlorine content). Large installations of 100-200 MW_{fuel} produce steam at 100-120 bar and 500-540°C. Steam cycles with reheating are used for sizes from around 75 MW_{fuel} .

The maximum electrical efficiency for a 20 - 50 MWe boiler without steam reheating is around 30% (net). The power/heat ratio at maximum heat supply is $0.3 \div 1$ to $0.5 \div 1$ depending on the parameters for fresh steam and the temperature of the heat supplied.

Environmental measures and emissions

A typical large-scale biomass CHP installation will be equipped with DeNO_x SNCR, fabric filters with dry flue gas desulphurisation and wet water and wet electrostatic filters for emission reduction. Typical flue gas concentrations for combustion of A wood and B wood with this type of flue gas scrubbing are (values for 11 vol.% O₂ in dry flue gas): Particulates < 1 mg/Nm³; SO₂ 5 - 10 mg/Nm³ and NO_x 65 mg/Nm³

Investments and operating costs

The following cost parameters are used in the SDE+ scheme (SDE+ 2014): Bio CHP: investment costs: € 1 500 - € 2 000 /kWth_input, fixed O&M costs: 80-110 €/kWth_input. For comparison

Bio boiler: investment costs: € 400 /kWth_input, fixed O&M costs: € 60/kWth_input.

6.1.4 Low temperature geothermal energy

Geothermal energy is a proven technology for low-temperature applications and is now used by 10 greenhouse horticulture companies, including Ammerlaan in Pijnacker. Experience shows that it is technically and economically attractive, but the technology is not yet fully developed, and so there are unexpected problems which add to the costs. The Netherlands Enterprise Agency estimates the potential at 17 PJ in 2020. The technical potential is considerably greater.

Figure 16 Geothermal energy plant at Ammerlaan in Pijnacker



6.1.5 Deep geothermal energy (> 5 km depth)

Deep geothermal energy is an option for producing steam at temperatures higher than 200°C. The technical potential is high, but its use has not yet been proved in practice. A joint venture of Parenco, Ballast Nedam and Alliander is carrying out a feasibility study of deep geothermal energy for the supply of steam at Parenco. The concept involves drilling to a depth of 6.5 km, which would supply 60 MWth at a temperature of 240°C. The

source will also supply residual heat to the surrounding area. The technique requires significant investment (ca € 110 million), but the operating costs are low. Others besides Parenco are conducting feasibility studies of deep geothermal energy.

6.1.6 Increasing the efficiency of a CHP installation by process integration

Another route is increasing the efficiency of CHP installations.

At AVEBE heat streams from CHP are integrated with process streams in the plant, resulting in efficiencies of > 90%. This high efficiency helps to reinforce the market position of CHP.

6.2 Other alternatives

The alternatives the five companies visited are working on are not the only possibilities for meeting the heat demand sustainably. Other options have also emerged from the discussions with the companies, feedback groups and other stakeholders. Some of these are still being developed.

1. Heat supply

Industry produces substantial streams of residual heat, some of which are at high temperature, and could potentially be used for low-temperature applications, such as greenhouse horticulture. An exploratory study of the use of residual heat from Rotterdam Port for greenhouse horticulture in Westland is currently being carried out.³⁷

2. Heat pumps

Heat pumps offer prospects for the conversion of low-value to high-value heat streams, and can thus help to reduce the heat demand. The Institute for Sustainable Process Technology [TKI-ISPT] is researching techniques for converting heat streams to higher temperatures. A pilot is running at Smurfit Kappa in Roermond. The aim is to achieve payback times of 2-3 years. The ISPT sets the total potential savings of this at 60 PJ³⁸. It is mainly used for applications with a heat demand lower than ca 200°C.

Another option, also based on heat pump technology, is the *HIDiC* [Heat Integrated Distillation Column] which can make distillation processes more energy-efficient and is therefore aimed at higher-temperature applications. The technique is still being used on a demonstration scale. The ISPT estimates the potential savings from this to be 11-20 PJ.

3. Power-to-Pressure

Power-to-Pressure is a technique which converts low-pressure steam to high-pressure steam with an electrically powered pump. It appears to be cost-effective when electricity prices are low. This is also being studied by TKI-ISPT.

³⁷ <http://www.duurzaambedrijfsleven.nl/63890/grontmij-studeert-op-restwarmte-rotterdam/>

³⁸ (TKI-ISPT, 2013)

4. HE steam boiler

This optimised steam boiler produces a relatively small amount of electricity which can be used 'within the plant'. This may potentially offer a positive earnings model. The concept was developed in the Netherlands, and is ready to be used in practice for the first time.

6.3 Potential savings, costs and contribution to renewable energy targets

Table 8 summarises the techniques and their potential.

The potential is based on the input from the Netherlands Enterprise Agency for the 'intensification' scenario of the Ministry of Economic Affairs' heat vision. If 53% of CHP facilities are shut down, 40.3 PJ heat must be generated in another way. The potential of alternatives is therefore comparatively limited.

Table 8 Techniques and potential

	In use/under development at:	Technically feasible	Potential in 2020 in PJ (achieved in 2012)
Steam from waste incineration plants	Akzo Nobel	✓	13 (7)
Steam from residue streams	Parengo, Eska Graphic Board	✓	Not known
Steam from biomass	Akzo Nobel	✓	17 (3)
Low-temperature geothermal energy	Ammerlaan - TGI	✓	13 (0.5)
High-temperature geothermal energy	Parengo		0
CHP optimisation / energy integration	AVEBE	✓	Not known

The costs of the options geothermal energy and biomass are higher than those of heat production from a CHP or gas boiler.

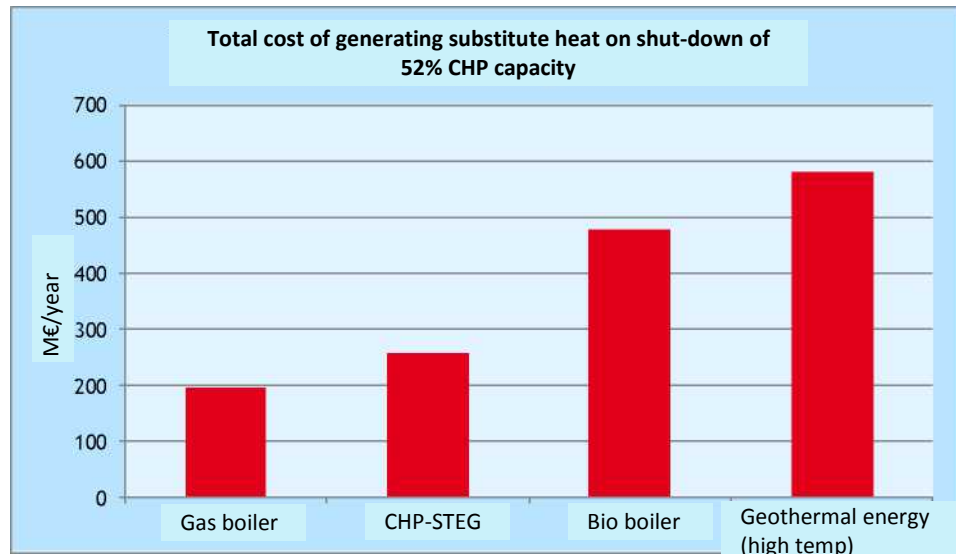
To illustrate this, Figure 17 shows the cost of producing 40.3 PJ industrial heat with a gas boiler, CHP-STEG, bio boiler and high-temperature geothermal energy. The CHP is assumed to be an industrial STEG, with the financial gap in 2020 allocated to heat production. The boiler gas price is assumed to be € 0.18/m³, which is the correction factor from the 2014 SDE+ scheme.

The basic amount from the SDE+2014 of € 11.8/GJ (solid biomass boiler >5 MWth) and € 14.4/GJ (geothermal energy heat > 3,300 m deep) has been taken for biomass and geothermal energy³⁹. This results in € 480

³⁹ The Netherlands Enterprise Agency, 2014, SDE+ 2014, <http://www.rvo.nl/sites/default/files/2014/02/Digitale%20brochure%20SDE%2B%202014.pdf>

million/year for production of heat in a bio boiler, and € 580 million/year for use of high-temperature geothermal energy.

Figure 17 Typical cost of generating 40.3 PJ heat from a gas boiler, CHP-STEG, biomass boiler and deep geothermal energy



Production of renewable heat in industry or greenhouse horticulture contributes to the achievement of the targets for renewable energy in 2020. This is cheaper than the production of renewable electricity. To illustrate this, the basic cost (installations > 10 MW) is € 31-43/GJ electrical energy produced for production from biomass, and € 38/GJ for production from offshore wind. This is substantially higher than the € 11.8/GJ for shallow geothermal energy, € 11.8/GJ for heat from biomass and € 14.4/GJ for deep geothermal energy⁴⁰. The higher cost of renewable electricity is due to its lower conversion efficiency.

⁴⁰ Source: Preliminary correction amounts from the 2014 sustainable energy production incentive for the payment of advances in 2014, the Netherlands Enterprise Agency, May 2014

7 Conclusions

CHP capacity

As at 1 January 2014, there is 8.9 GWe total CHP production capacity: 2.8 GWe in industry, 3.1 GWe in greenhouse horticulture and 3.6 GWe in the built environment. These CHP installations produced 42% of the electricity in the Netherlands 2012.

Some of the CHP capacity has a degree of flexibility.

These installations are able to reduce electricity production if prices are low, and increase it when prices improve. The capacity in greenhouse horticulture is flexible. Around half of the capacity in industry can be regarded as flexible, the other half is 'must-run'.

The installed production capacity is falling as a result of unfavourable market circumstances. In industry around 1.0 GWe has been shut down in the last four years. Companies say that they will shut down more capacity in the coming years, including at least 0.9 GWe in industry.

Position of CHP in the energy market in 2020/2030

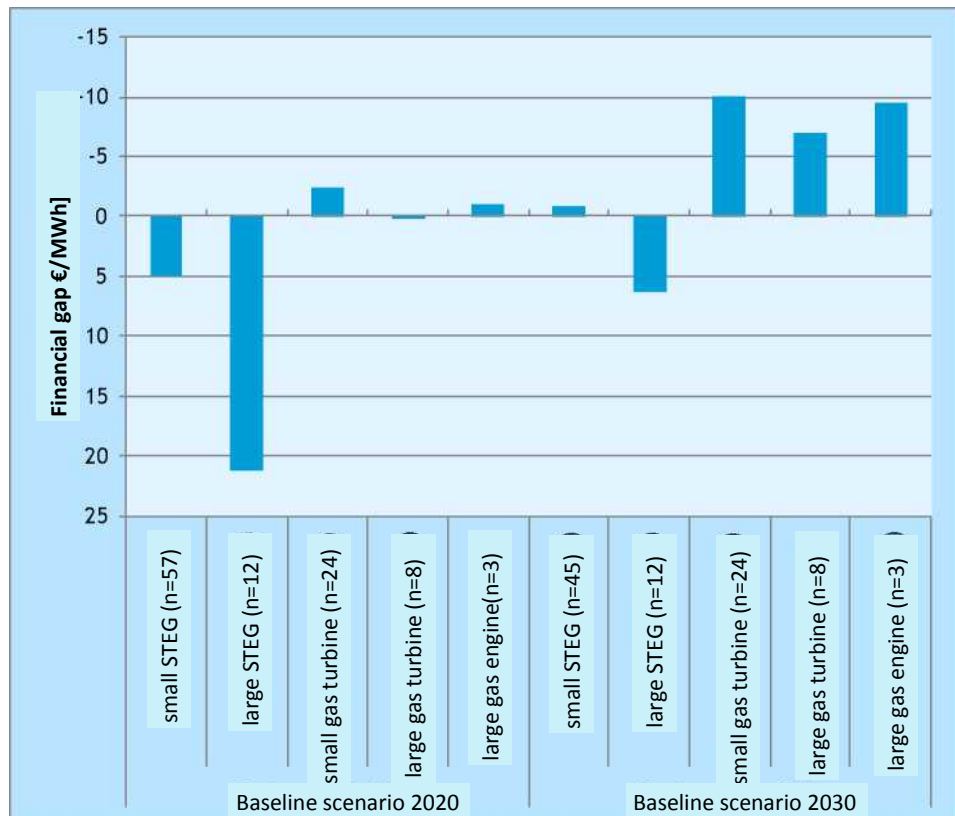
Detailed analysis shows that CHP installations will also be in an unfavourable market position in 2020. 53% of the installed capacity has a financial gap. 67% of this is in industry and the built environment. The installations in greenhouse horticulture operate just about cost-effectively.

The unfavourable market position of CHP is caused by a combination of coinciding factors (limited growth in demand, a large amount of renewable energy from Germany, growth in the production capacity of fossil power stations, low CO₂ prices, low coal prices, relatively high gas prices).

Simulation modelling shows that in 2020 gas-fired power stations will be faced with more difficult market circumstances than CHP installations, and their operating hours will have fallen almost to zero.

In 2030 the market circumstances will be more favourable as a result of the shut-down of fossil capacity and rising demand. This will improve the position of CHP installations. This modelling is based on the CHP capacity in 2014. However, a large part of this may already have been shut down by 2030. Figure 18 shows the financial gaps of CHP installations in 2030 and 2030:

Figure 18 Financial gaps of CHP installations in 2020 and 2030. A financial gap means that the installation is not operating cost-effectively



We examined the position of CHP in other scenarios for changes in CO₂ prices and renewable production capacity in a sensitivity analysis. We also looked at the position of CHP installations if a mark-up is applied again. A mark-up is the willingness in the market to pay more than the marginal cost price for power, in a situation where demand and supply are in balance. The analysis shows that:

- at a higher CO₂ price (€ 71/t CO₂, in accordance with the WEO 450 ppm scenario) the cost-effectiveness of CHP installations improves considerably.
A major reason for this is higher electricity prices, which make all types of CHP installation cost-effective.
- If a mark-up is applied again to electricity production in the market the cost-effectiveness improves considerably. In the calculation example of € 8.1/MWh all types of CHP installation are cost-effective again.
- If there is a high level of renewable energy, the absolute position of CHP is worse, because electricity prices are lower. This also affects other fossil units. The position of flexible units (including flexible CHP) is better than must-run units when there is a high level of renewable energy.

Impact of shutting down CHP installations on energy use and CO₂ emissions

If the CHP installations that are not cost-effective are shut down their production of heat and electricity will be replaced. Depending on the type

of installation that takes over, this may increase primary energy use and CO₂ emissions. The final energy use does not change. Three variants were studied: replacement by the reference facilities (without renewable energy), replacement by gas-fired power stations and replacement by coal-fired power stations. The gas-fired power stations are Dutch power stations, the coal-fired power stations are mainly power stations abroad. The simulation indicates that replacement by gas-fired power stations is less likely given the poor position of gas-fired power stations in the ranking. Replacement by (foreign) coal-fired power stations seems probable, provided there is sufficient transport capacity. More detailed analysis of this is required.

The impact on primary energy use in 2020 is shown in Table 9. The table shows how much the primary energy use grows if 53% of the CHP capacity (the part that will not be cost-effective in 2020 according to the analysis) and 87% (that part plus the CHP installations in greenhouse horticulture) respectively is shut down. The emissions are calculated on the basis of the number of operating hours of installations in 2020 and 2030. The figures are higher when based on the operating hours in 2012.

Table 9 Changes in primary energy use on shut-down of CHP capacity

Substitute electricity produced by	53% PJp shut down	87% PJp (incl. CHP installations in greenhouse horticulture) shut down
Reference capacity	40	68
Gas-fired power stations	11	24
Coal-fired power stations	40	68

The emissions of CO₂ in 2020 increase by 0.6 and 0.9 Mt respectively if electricity production is replaced by gas-fired power stations. If coal-fired power stations take over production, the increase is considerably higher at 7.6 and 11.6 Mt respectively.

A factor that contributes to the unfavourable economic position of CHP is the growth in the share of renewable electricity. For the electricity production system as a whole, this contributes significantly to reducing the primary energy use: 143 PJp in 2020 and 251 PJp in 2030⁴¹.

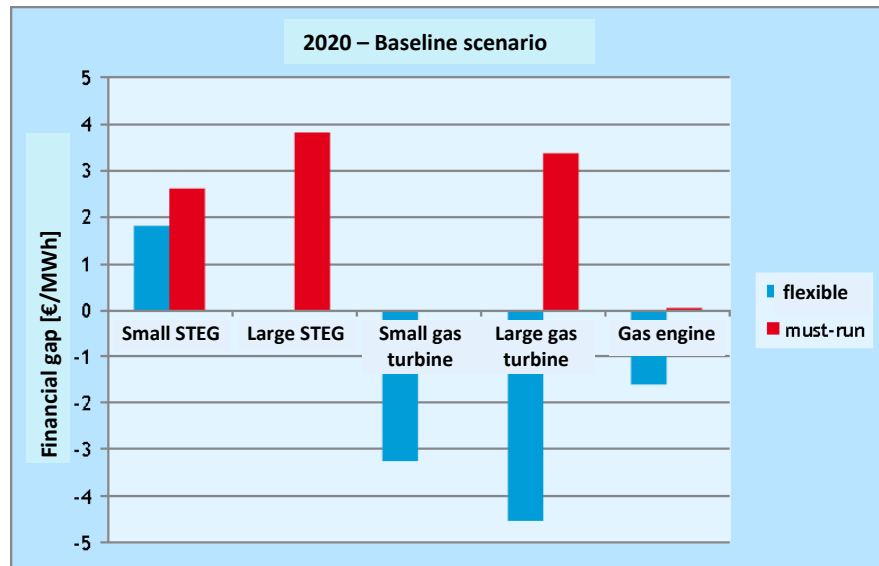
Position of flexible CHP installations in the energy market in 2030

The analysis shows that, in industry and greenhouse horticulture, flexible CHP installations generally operate more cost-effectively than must-run installations. This is true both on the basis of variable costs and benefits, and taking account of the investments. The pattern can be seen particularly in gas turbines and gas engines, but is less marked with STEG installations. Figure 19 shows the position of the various types of

⁴¹ Calculated for the baseline scenario.

installation in 2020.

Figure 19 Cost-effectiveness of flexible and must-run CHP installations in 2020



It is technically possible to convert must-run CHP installations to flexible installations. The main options are modifying the flue gas boiler, installing an additional boiler and installing a heat buffer. This can achieve 100% flexibility, with switching speeds of < 1 hour. The total cost of converting industrial must-run CHP installations (1.62 GWe) to flexible operation is ca € 75-150 million.

Flexible CHP installations can help to cover shortages by producing additional electricity. The simulation looked at whether other flexible options do the same and showed that peak load gas turbines and demand management are not used, while pumped storage (via interconnection) is used.

Flexible CHP installations can also help to deal with surpluses. On the one hand by shutting down production temporarily, and on the other by using Power-to-Heat to convert surpluses into heat. The simulation shows that this is mainly used in a scenario with a high level of renewable energy. Power-to-Heat can be integrated into CHP installations, but can also be connected to other boiler installations.

The market rewards the supply of production in times of shortage with higher prices. This happens in various markets, such as the day ahead market, intra-day market and the balancing market.

Converting installations to flexible operation entails additional costs as a result of market conditions and energy tax. These are:

- Energy tax: CHP installations are only eligible for an exemption from energy tax if they have an electrical efficiency of at least 30%.
- Energy tax: district heating installations are only eligible for a reduced energy rate if they produce at least 50% of their heat with CHP.

- When taking power from the network, transport fees must be paid to the network operator.

According to companies with CHP installations, these are major obstacles to increasing flexibility.

Alternative options for meeting the industrial heat demand

There are various alternative options for meeting the heat demand in industry sustainably and/or efficiently:

- Steam from waste incineration plants is already used by various clusters of companies. It appears to be technically and economically feasible. Potential for further expansion is limited.
- Use of biomass for steam production is technically feasible. The critical point is the availability of biomass and changes in the cost. Biomass stocks in the Netherlands are limited and there is competition from other applications.
- Use of industrial residue streams for steam production is also technically feasible. However available waste streams are limited.
- There is great technical potential for geothermal energy in principle. It is a proven technology for low-temperature applications, and is now used by ten glasshouse horticulture companies. The use of the technology may lead to unexpected problems that can create additional costs.
Deep geothermal energy (> 5 km deep) is an option for producing steam at temperatures higher than 200°C. There is a lot of technical potential, but the technique has not yet been fully tested.
- The efficiency of a CHP installation can sometimes be increased by integrating streams from CHP with the company's processes. AVEBE has been using this method for a long time to achieve efficiencies >90% for CHP, which is helping to strengthen the market position of CHP.

In summary, the potential for using residual heat from waste and/or residual heat from waste incineration plants is limited. Biomass and geothermal energy have greater potential, but the production costs of heat are substantially higher than the costs of producing heat in boilers or CHP installations. The replacement of the production of 40.3 PJ heat (the heat production lost on shut-down of 4 600 MWe, 53% of capacity), requires a subsidy of around € 480-580 million a year. However, heat production from renewable sources does contribute to the achievement of the renewable energy target. The costs are relatively low in comparison with those of producing renewable electricity.

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Annex A Steering committee and feedback group

Steering committee

E.J. de Vries, Ministry of Economic Affairs, chair, first two meetings
M. Wagenaar, Ministry of Economic Affairs, chair last two meetings
K. den Blanken, Cogen Nederland
M. Blanson Henkemans, Ministry of Economic Affairs
R. Gerrits, VNCI [Netherlands Chemical Industry Association]
E.H. Kloppenborg, Ministry of Economic Affairs
C. Lambregts, VNP [Netherlands Paper and Cardboard Industry Association]
R.P.M. van Mossevelde, the Netherlands Enterprise Agency
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Feedback Group

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C. Lambregts, VNP
R. Gerrits, VNCI
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Annex B CHP production capacity as at 1 January 2014

Current capacity

Table 10 summarises the CHP capacity in the various sectors, distinguishing between flexible, partly flexible (or partial spark-spread) and 'must-run' CHP installations. These are referred to in the table as Flex, PSP and MR respectively.

Table 10 Composition of CHP production capacity (source: Energy Matters)

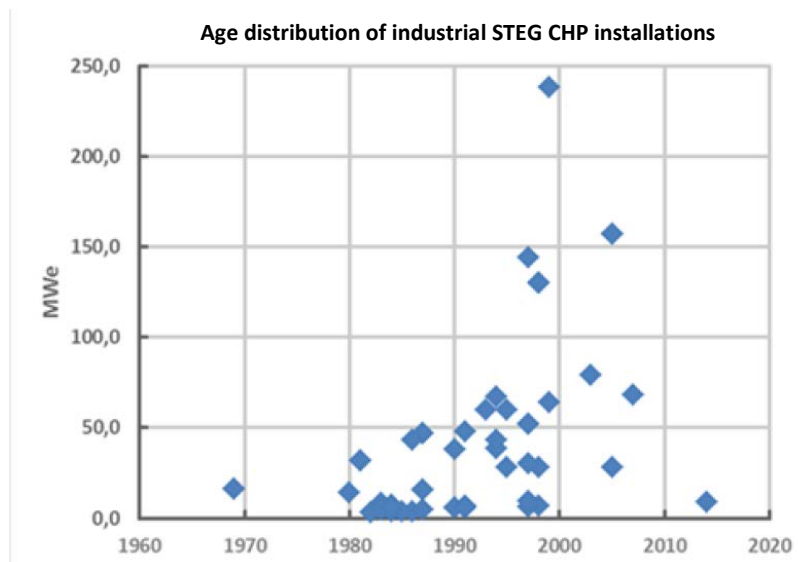
	Gas engine		STEG			Gas turbine			Steam turbine			Total
	Flex	MR	Flex	PSP	MR	Flex	PSP	MR	Flex	PSP	MR	
Refineries			305	314	48	21			24			712
Food industry			85	45.5	16.5	117			44		18	326
Chemical industry			238	628	140	58	40.4	54.6	28	22	24	1 233
Paper industry			122		85	4			6			217
Other industry			106		182	72	4.8	1.2	8			374
Total industry		19	856	988	472	272	45	55.8	110	22	42	2 862
Greenhouse horticulture	3 060											3 060
Built environment	580		2 055								321	2 956
<i>Total</i>			2 911	1 975	472	272	90	56	110	44	363	8 879

Age structure of CHP installations

Most CHP installations date from the period 1980-2005. To illustrate this, Figure 20 shows the age structure of STEGs and gas turbines.

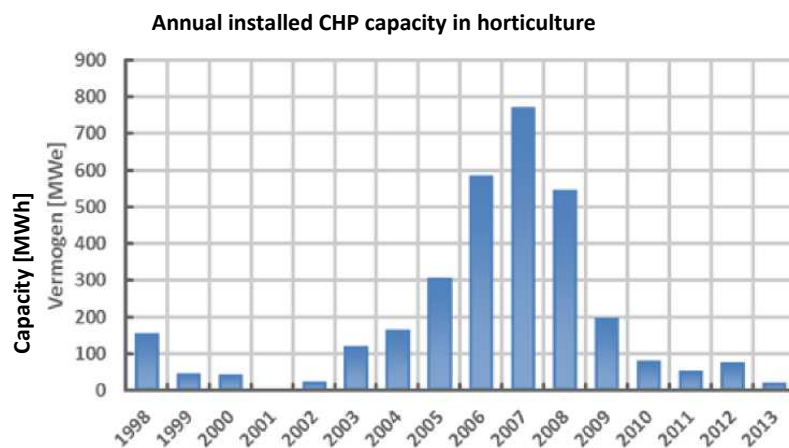
The CHP installations in greenhouse horticulture were installed slightly later, in the period 2000-2010.

Figure 20 Age structure of STEG CHP installations



Source: Energy Matters

Figure 21 Installed capacity in greenhouse horticulture

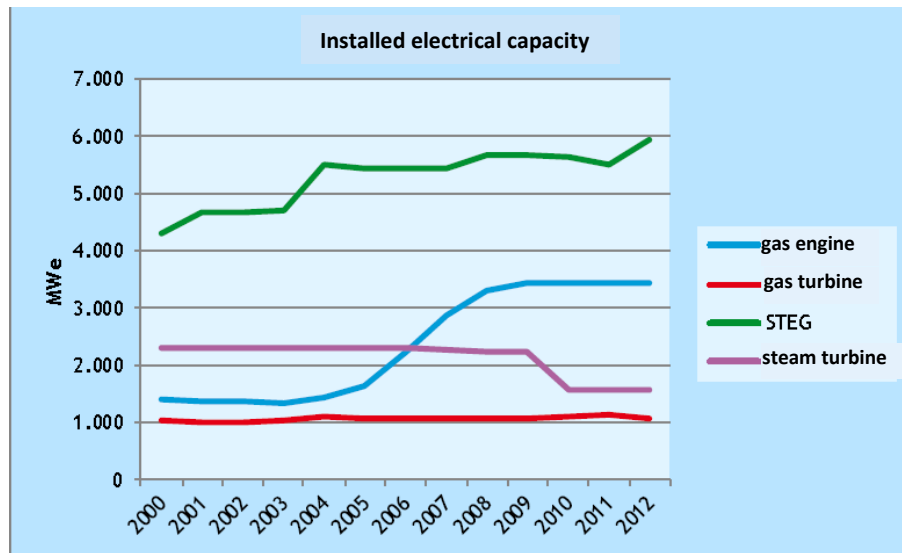


Source: Energy Matters

Changes in production capacity and electricity and heat supplied

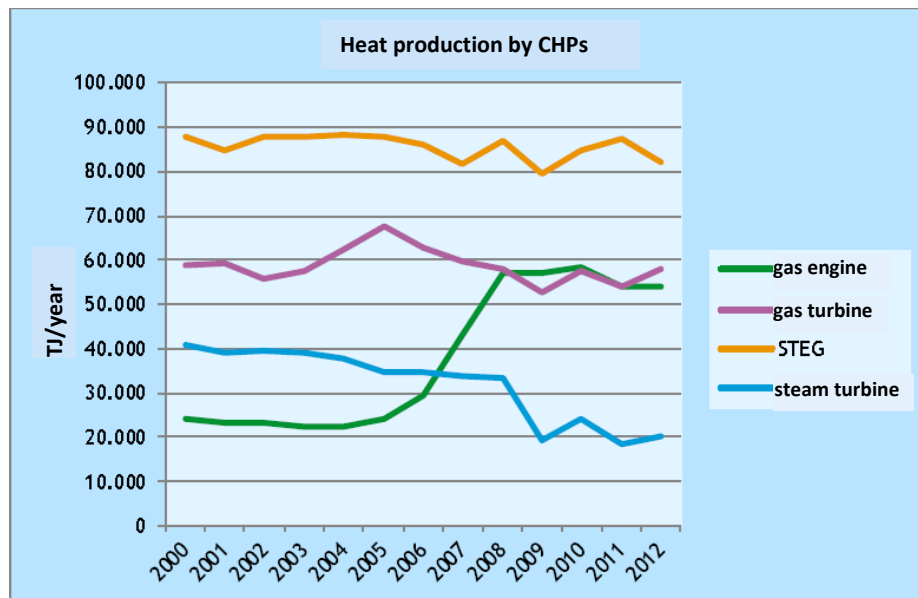
According to figures from Statistics Netherlands, in the years leading up to 2008-2012 the installed capacity had not begun to fall significantly, as can be seen in Figure 22: there is a fall in the installed capacity of steam turbines, but also a growth in the production capacity of STEGs. However, the electricity production of CHP installations, particularly the STEGs, began to fall in 2010. This is an indication that more installations began to operate at part load (Figure 22). However, during these years the heat production of CHP installations remained stable.

Figure 22 Changes in installed capacity of CHP installations from 2000-2012

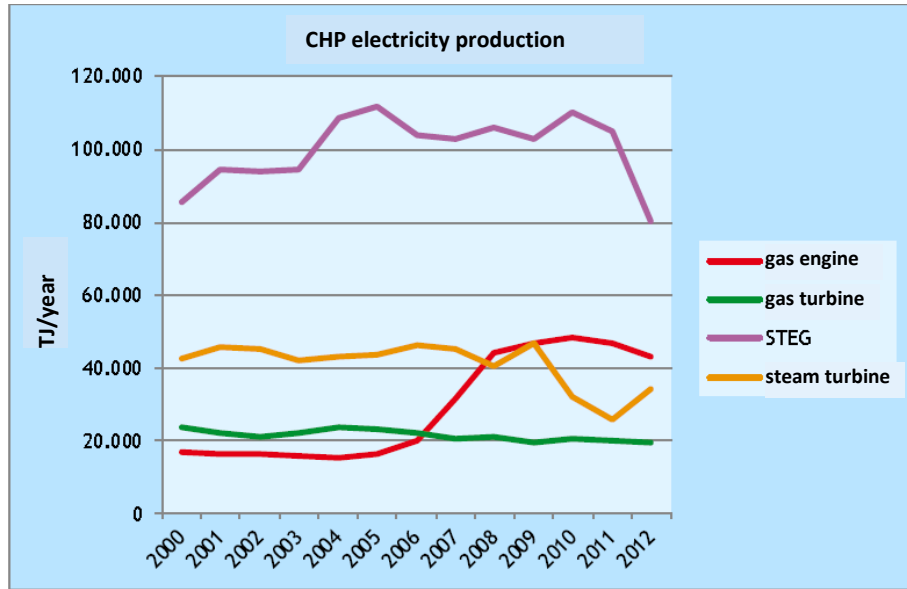


Source: Statistics Netherlands

Figure 23 Production of heat and electricity by CHP installations in 2000-2012



Source: Statistics Netherlands



Source: Statistics Netherlands

Annex C Increasing the flexibility of CHP installations

Source: Energy Matters

Technical measures for converting CHPs to more flexible operation

The following are popular or known ways of increasing the flexibility of CHPs:

- a Separate boiler, combined with start/stop operation.
- b Installation of burners in the flue gas boiler with additional combustion air blower.
- c Separate combustion chamber in addition to gas turbine from which the flue gases are fed through the flue gas boilers.
- d Heat buffer (for district heating).
- e Installation of variable inlet guide vanes.
- f Operation at part load for own use.
- g Modification of combustion chambers.
- h Installation of regulating device to control the combustion process in the gas turbine.

a Separate boiler, combined with start/stop operation

It is, of course, technically feasible to install and connect a separate boiler for heating water or steam provided there is enough physical space at an existing site. Operating in start/stop mode, for example only on working days when the market price is high enough, could be an option. At present, with the current spark-spread during peak hours (working days from 8.00 to 20.00), that is not cost-effective but if the market recovers it will soon become an option. Depending on the type of gas turbine, a controlled start-stop cycle takes an equivalent number of operating hours and the variable maintenance costs are therefore higher. The maintenance costs for cyclical operation (250 starts a year) are 50% to 100% higher than normal. Maintenance costs are reduced by provisions for keeping the gas turbine and boiler hot when not running. These include a flue gas valve on the chimney to counteract the natural draught of the boiler and gas turbine. For a large STEG (200-350 MWe) a start-up time of 30 to 60 minutes from hot (maximum 8 to 12 hours shut-down) to full load must also be allowed for, while for a smaller gas turbine, the start-up time ranges from 10 minutes (aeroderivative) to 20 minutes (stationary turbine) (20 to 50 MWe).

b Installation of burners in the flue gas boiler with additional combustion air blower

The installation of burners in the flue gas boiler combined with a combustion air blower (fresh air mode) is technically a complex modification. Flue gas recirculation is often needed to comply with the statutory NO_x emission requirements and improve the boiler efficiency. This requires the chimney to be branched with a second flue gas circulation ventilator. There is not always room in the flue gas pipe

between the gas turbine and the boiler to fit a pipe burner, but allowance has sometimes been made for this. A by-pass chimney is also needed to switch rapidly from gas turbine mode to fresh air mode. The advantage of this modification is that it avoids the need to invest in a separate boiler.

Boilers with a supplementary burner but without provision for fresh air mode can sometimes be adapted for fresh air mode. Here too, there must be enough room to fit valves in the flue gas pipe, and a combustion ventilator, a by-pass chimney and flue gas recirculation pipes outside the boiler.

The capacity to be added is limited by the construction. In standard boiler design, the walls are not cooled but only insulated internally and protected with plating, so the maximum admissible temperature of the flue gases is around 850°C. At higher temperatures a lining must be fitted, possibly with cooling. In an existing situation the cost of this is too high to be realistic.

c Separate combustion chamber next to the gas turbine from which the flue gases are guided into the flue gas boiler

This option is similar to the previous one but Energy Matters is not aware of any examples of it. It is technically complex because the valves in the flue gas pipe must be suitable for the higher temperature (up to ca 800°C). Flue gas recirculation is probably also needed to achieve sufficiently low NO_x emissions.

d Heat buffer (for district heating)

As it is impossible to buffer enough steam, this option is only applicable to district heating. Some places have hot water buffering in large tanks. The new district heating plant in Diemen, for example, has a heat buffer 50 metres high and 26 metres in diameter. The maximum capacity is 22 000 m³ with a maximum storage capacity of 1 800 MWh. This seems a lot but is around five full-load hours of heat storage from the power station.

However this is a very cost-effective measure for 90/70°C systems behind a gas engine for greenhouse horticulture, building or district heating, for example.

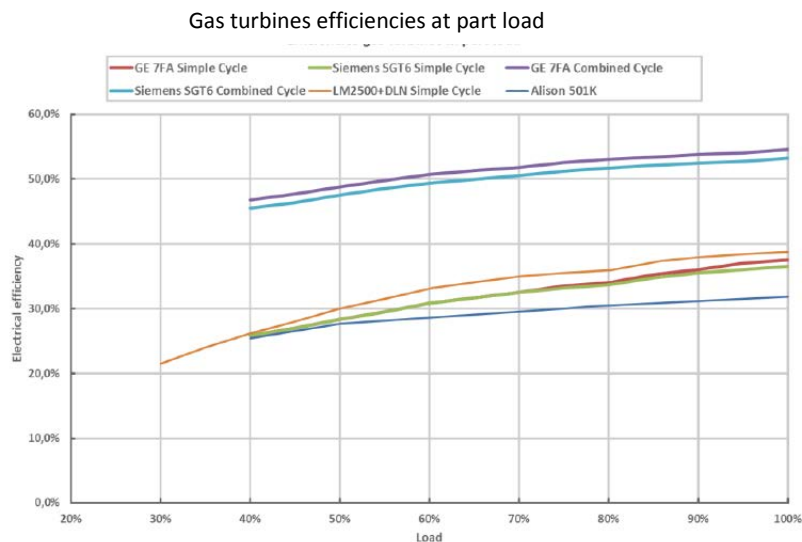
The heat buffer at the power station in Diemen is designed for 140°C and 7 barg.

e Installation of variable inlet guide vanes

Variable inlet guide vanes (VIGV) on the compressor ensure that the quantity of intake air can be controlled. Aero-derivative gas turbines have VIGV as a standard part of their design. Stationary turbines (for example the Siemens or GE Frame turbines) do not have VIGV as standard. Gas turbines which operate constantly at full load do not need VIGVs, but part load efficiency falls rapidly without them. However, as far as Energy Matters is aware, most gas turbines in industry are fitted with VIGVs.

f Operating at part load for own use

Many industrial CHPs are designed for steam demand and return surplus electricity to the network. A possibility for optimising income is to produce primary electricity for internal use (demand side) and only supply it to the network when the current market price (APX of PV) is high enough. This can be done up to a certain level by running the gas turbine at part load. However, the efficiency does fall at part load, even with VIGVs. Most gas turbines have an efficiency curve with a limited efficiency loss of 5 to 7% (electrical) at up to 70 to 60% load. The required deNO_x emission level is often not achieved below this. In practice, that means that a gas turbine is not to be operated at a part load below 60% to 70%. A shortage of steam will then have to be covered by the supplementary burner or a separate boiler. Finally, the fact that the variable maintenance costs are linked to operating hours is also a disadvantage. Although there is a certain relationship between load and degradation, many maintenance contracts are based on operating hours. At a continuous load of 70% the maintenance costs per kWh will therefore rise by a factor of 1.4. The overheads also put pressure on lower production and will therefore be higher per kWh. The fact that the gas turbine and the boiler are up to temperature and can be adjusted upwards reasonably quickly is an advantage. The smaller gas turbines in particular (<60 MWe) can be adjusted upwards at a rate of 20%/min. For larger STEG power stations this rate is limited to 3 to 5%/min. This may provide an additional earnings model.



g Modification of combustion chambers

Combustion chambers are not modified to make them more flexible. They have been, or will be modified to comply with emission requirements. This will reduce the flexibility of a Dry-Low-NO_x (DLN) type because the air feed over the various burner stages is much more sophisticated than with a conventional one-stage burner. A burner can also be adapted for steam or water injection (STIG).

There is little point in doing this in the current economic climate as more electricity is produced than (net) steam. Additional heat and condensate is also lost through the chimney. The current strict NO_x emission requirements can also be met with steam or water injection. In theory, an alternative for meeting the NO_x emission requirement at part load is to install SCR. In practice this is difficult and scarcely an option from an economic point of view. SCR (selective catalytic reduction of NO_x) must be carried out within a temperature range of 350 to 450°C. It is too hot immediately behind the gas turbine or supplementary burner. A place to fit the SCR blocks must be found somewhere in the flue gas pipe between the tube bundles. As the blocks are very large this is virtually impossible in an existing boiler.

h Installation of regulating devices to control the combustion process in the gas turbine

This measure is not relevant. The control of combustion chambers is complex. Modern DLN combustion chambers often have four- or five-stage combustion. The combustion air is fed in to ensure a constant fuel/air ratio in the actual burner, the premix burner. The part-load constraint and the low part-load efficiency below 60% is caused not so much by the regulability of the burner as by the thermodynamic behaviour of the gas turbine. The regulating devices must be improved to make gas turbines suitable for a wider range of natural gas qualities. The fact that suppliers must gain experience with the dynamic changes caused by the changing quality of natural gas is a factor here. Very little experience has been gained on this subject.

Investments for modifying CHPs during revamp retrofitting

A total investment comprises components and the additional cost of installation and full assembly including connections (gas/electricity/water/flue gas, etc.) and civil engineering costs (building/foundations). The additional costs in particular depend on the situation. The component costs depend primarily on the scale. Indicative sums for the various modifications are given below for global calculations. For individual situations, the local situation must be worked out in more detail.

a Separate boiler, combined with start/stop mode

Boilers can be divided into hot water boilers (T<100°C) and heating water or steam boilers (T>100°C).

The following can be assumed for heating water boilers: € 75/kW for boilers up to 500 kW, € 60/kW for boilers from 500 kW to 2 000 kW and € 40/kW above that. This is the basic purchase price of the boiler. The cost of a fully installed boiler house will be 100 to 200% higher (in other words twice or three times as high).

For a heating boiler and steam boiler for process steam the following can be assumed: € 150/kW for boilers of 30 t/h (superheated, ca 22 MW) and € 120/kW for boilers of 100 t/h (ca 72 MW), fully installed

including boiler house.

b Installing burners in the flue gas boiler with additional combustion air blower

The estimated cost of installing an additional combustion air blower with valves and pipes for flue gas circulation, a supplementary burner and a by-pass chimney is ca € 40/kW for a boiler of 30 t/h and ca € 30/kW for a boiler of 100 t/h. This assumes that this modification is technically feasible.

c Heat buffer (for district heating)

The guide figure for a heat buffer of 200 m³ for a gas engine, for example, is € 250/m³, fully installed. The cost of a heating water buffer of 22 000 m³ at a pressure of 7 barg is roughly estimated to be € 5 million.

Annex D NO_x emissions from CHP installations

NO_x emission requirements under the Activities Decree

Table 11 shows the NO_x emission requirements to be met by CHP installations. The requirements for steam boilers are also included for comparison⁴².

Table 11 Emission requirements under the Activities Decree for Combustion Plants (from 1 January 2016/1 January 2017)

		NO _x (mg/m ³)	
Gas turbine installation	<50 MWth	140 (at 3% O ₂)	1 Jan 2017
	>50 MWth	75 (at 15% O ₂)	1 Jan 2016
	>50 MWth, as total efficiency <75%, of electrical efficiency <55%	50 (at 15% O ₂)	ditto
Gas engine	<2.5 MWth	340 (at 3% O ₂)	1 Jan 2017
	>2.5 MWth	100 (at 3% O ₂)	1 Jan 2017
Steam boiler	gas-fired	70 (at 3% O ₂)	1 Jan 2016
Steam kettle	coal-fired	100 (at 3% O ₂)	1 Jan 2016

Possible measures

Possible measures for ensuring compliance with this:

Dry low NO_x burners

Low NO_x combustion chambers, dry low NO_x burners (DLN), have been developed for many gas turbines which can be used to achieve emissions of 25 ppm or lower. The additional costs for a DLN turbine vary significantly and depend on the type and make of gas turbine. Dry low NO_x burners can be retrofitted if the combustion chamber has been developed for the particular gas turbine and meets the emission requirements. The investment costs for retrofitting are estimated to be three times as high and the variable costs 50% higher than for a new burner.

MWe	Investment €/kWe	Variable €/MWe/hour
0.4	288	6.6
0.9	167	3.8
1.5	117	2.7
2.0	96	2.2
2.1	93	2.1
3.3	62	1.4
4.5	61	1.4

⁴² InfoMil Knowledge Centre, 2014, emission requirements for combustion plants, <http://www.infomil.nl/onderwerpen/klimaat-lucht/stookinstallaties/hulpmiddel/>

Installing a dry-low-NO_x (DLN) type burner reduces the flexibility of the gas turbine because of the complexity of combustion, which often has four to five stages.

Steam or water injection

A burner can also be adapted to the BEMS standard by steam or water injection (STIG). There is little point in doing this in the current economic climate because more electricity will then be produced and less steam. Additional heat and condensate is also lost through the chimney.

SCR

The Activities Decree/BEMS includes an emission requirement of 100 mg/Nm³ (ca 28 g/GJ) for the larger gas engines (2.5 MWin and above). SCR (selective catalytic reduction) is used to achieve this standard. The investment costs of implementing a DeNO_x SCR for a gas engine and the variable operating costs are summarised below:

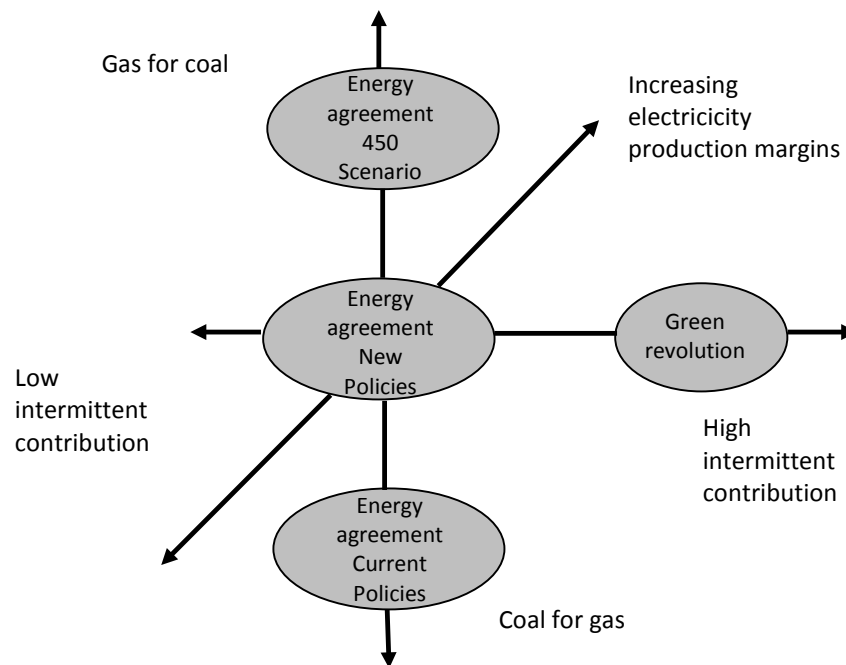
MWe	Investment €/kWe	Variable €/MWe/hour
0.4	288	6.6
0.9	167	3.8
1.5	117	2.7
2.0	96	2.2
2.1	93	2.1
3.3	62	1.4
4.5	61	1.4

Annex E Basic assumptions of the scenarios

Figure 24 shows the three axes along which the scenarios are drawn up to evaluate the future position of CHP in the energy market. The three axes are:

- the CO₂ and fuel prices;
- the amount produced by renewable energy;
- the mark-up.

Figure 24 Scenarios for future development of the energy market



Fuel and CO₂ prices

These are based on the IEA's 2013 WEO (world energy outlook) scenarios (2013). There are three scenarios: 'Current Policies', 'New Policies' and '450 Scenario'. 'New policies' is the central scenario, which is followed in the baseline scenario. Two additional scenarios are also studied:

- 'Current policies' is used in the low CO₂ prices scenario. This assumes less international climate policy and lower CO₂ prices.
- The high CO₂ prices scenario. This is based on the '450 scenario', which assumes that there will be an international climate policy, resulting in high CO₂ prices.

Table 12 shows the prices of gas, coal and CO₂ for the three price scenarios:

Table 12 Prices for fuels and CO₂

Project scenario	WEO-2013 scenario	Gas price (€ ₂₀₁₂ /GJ)		Coal price (€ ₂₀₁₂ /GJ)		CO ₂ price (€ ₂₀₁₂ /Mt)	
		2020	2030	2020	2030	2020	2030
Baseline:	New policies	8.7	9.0	2.8	2.9	15.0	24.8
Low CO ₂ -prices	Current policies	9.0	9.8	2.9	3.1	11.3	18.8
High CO ₂ -prices	450 ppm	8.4	7.4	2.3	2.3	26.3	71.4

Growth in the amount of intermittent renewable energy

This is based on estimated capacity changes in the Netherlands and other countries in North-West Europe. The change in capacity in the Netherlands is based on the SER Energy Agreement supplemented by the forecasts from the TenneT 'Quality and Capacity Document 2013'⁴³ KCD2013. Changes in capacity abroad are based on the ENTSO-E 'Scenario Outlook and Adequacy Forecast 2014-2030'⁴⁴ (ENTSO-E, 2014).

In addition to the baseline scenario, we studied a scenario with an even larger proportion of renewable energy production, 'high level of renewable'. This is based on the realisation of the SER Energy Agreement together with an unexpectedly strong growth of solar PV in the Netherlands, and strong growth of renewable energy abroad.

- Dutch capacity change: in line with the baseline scenario with stronger growth for onshore wind (+33%) and offshore wind /solar PV (+50%),
- Foreign capacity change: in line with the baseline scenario +33% wind/solar PV.

Table 13 shows the installed capacity for the Netherlands for solar and wind energy in the 'high renewable' scenario, compared with the values in the baseline scenario.

Table 13 Capacity of renewable energy in the various scenarios

(MW)	2012 - Baseline	2020 - Baseline	2030 - Baseline	2030 - High renewable energy
Solar	365	4 000	8 000	12 000
Wind	2391	8 050	12 000	17 000

⁴³ This document presents a scenario analysis of the future developments in the Dutch electricity market for the period 2013-2023, with the aim of identifying potential bottlenecks in the TenneT network.

⁴⁴ This document presents a scenario analysis of future developments in the ENTSO-E markets for the period 2013-2030, with the aim of identifying potential bottlenecks in electricity supply in the ENTSO-E region.

'Mark-up'

This scenario is based on the electricity production margins in the Dutch market in 2000-2006. In the current market, with overcapacity, these no longer exist. This scenario reflects the restoration of the balance in the market. A mark-up of € 8/MWh is applied to all electricity produced.

Annex F North-West European market simulation model: description model and basic assumptions

F.1 Description model

In this study the use of the Dutch CHP power stations and the electricity prices are determined by the DNV GL North-West European market model. The model simulates the electricity market from a *Day-Ahead* perspective⁴⁵: the units offer their electricity on the basis of their marginal costs to meet the national electricity demand.

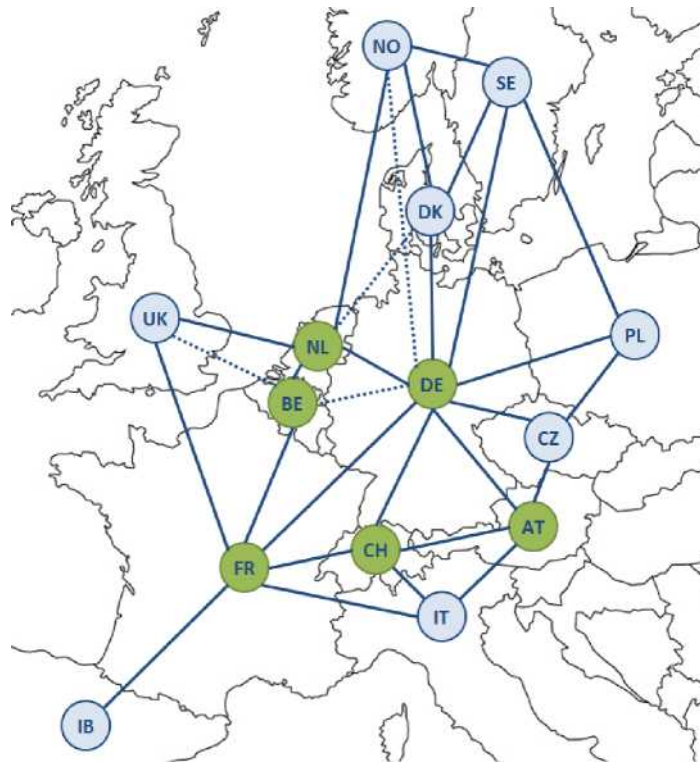
The countries (/electricity markets) are linked to each other through interconnectors, exchange being limited by the available transmission capacity. Optimisation is carried out in PLEXOS (see box *PLEXOS*).

Figure 25 shows the topology of the model.

Important inputs for the model are: the production capacity (thermal and renewable), fuel prices, electricity demand profiles, transmission capacity.

⁴⁵ Intra-day trading is not included, so we have not looked at the possible income of (flexible) CHP power stations from intra-day trading.

Figure 25 Summary of the topology of the simulation model. The green countries are core countries. The light blue countries are satellite countries: these are modelled in less detail



F.2 Production capacity in the Netherlands

This market model contains the electricity production capacity of the North-West-European countries (see Figure 25), including both thermal and sustainable capacity. The thermal power stations in the core countries (the Netherlands, Germany, Belgium, France, Switzerland and Austria) are individually simulated in the model. The production facilities in the surrounding countries are aggregated by technology.

(MW)	2012 - Baseline	2020 - Baseline	2030 - Baseline	2030 - High renewable energy
Non-CHP units				
Solar	365	4 000	8 000	12 000
Wind	2 391	8 050	12 000	17 000
Nuclear	474	474	0	0
Coal	4 050	4 402	4 402	4 402
Gas - STEG	6 913	7 030	11 034 ⁴⁶	6 034
Gas - other	1 825	964	145	145
Other (incl. biomass and waste)	1 401	1 600	2 695	2 695
CHP units				
Gas turbine	372	372	372	312
STEG	4 361	4 370	4 370	3 606
Gas engine	3 575	3 575	3 575	7 150
Steam	496	496	496	496
Total	26 223	35 333	47 089	53 840

F.3 Interconnection capacity

The Dutch electricity market is linked to the neighbouring countries. In the next few years this connection will be expanded by increasing the interconnection capacity between the countries and making more capacity available to the market. Table 14 summarises the available transmission capacity for the wholesale market.

Table 14 Transmission capacity.

(MW)	2012 - Baseline	2020 - Baseline	2030 - Baseline	2030 – high renewable
The Netherlands - Germany	2 450	3 950	3 950	3 950
The Netherlands - Belgium	1 400 ⁴⁷	1 400	1 400	1 400
The Netherlands - Norway	700	700	1 400	1 400
The Netherlands - England	1 000	1 000	1 000	1 000
The Netherlands - Denmark	0	700	700	700
Total	5 550	7 750	8 450	8 450

Source: ENTSO-E, 2012.

⁴⁶ This growth is assumed on the principle that national production capacity must be able to meet the growth in demand. However in the current market circumstances gas-fired power stations have been shut down and may be decommissioned.

The assumption may thus be an overestimate. The same applies if the analysis is used that the existing CHP capacity remains in operation, while in reality CHP installations are likely to be shut down.

⁴⁷ Based on the net transfer capacity, as published by ELIA (the Belgian network operator).

Table 15 Growth in demand in the Netherlands

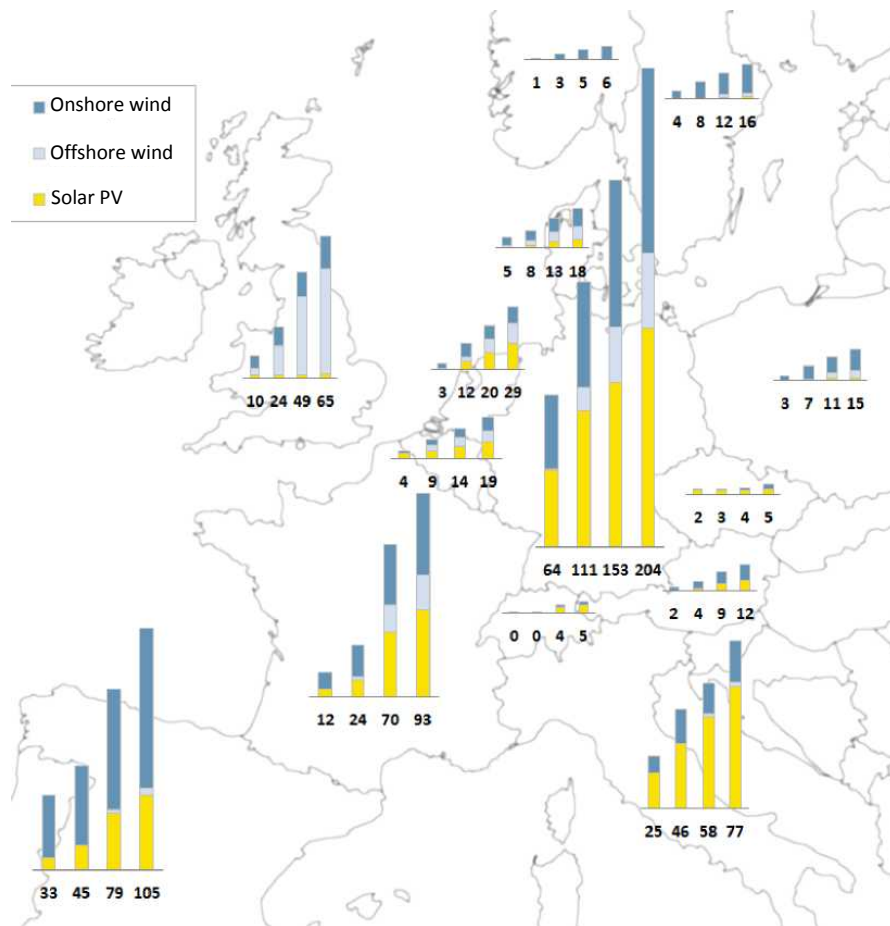
	Electricity demand	Annual growth (average)
2012	115 TWh	
2020	131 TWh	1.6%
2030	156 TWh	2.2%

Source: TenneT (2013), ENTSO-E, 2013.

F.4 Production capacity in surrounding countries

The simulation model also processes the production capacity in surrounding countries. The following data are used for renewable energy (Figure 26). The data are in line with ENTSO-E forecasts.

Figure 26 “Installed wind and solar capacity in the various North-West European countries. The four columns correspond to the four different scenarios: 2012-baseline, 2020-baseline, 2030-baseline and 2030-high renewable. The figure under the columns is the total wind and solar PV capacity in gigawatts.”



F.5 CHP capacity in the Netherlands

The CHP units in the Netherlands are modelled individually, with the exception of the gas engine units which are aggregated for reasons of uniformity and because of the complexity of the calculations. The CHP units are classified by sector (chemicals, refining, food and drink, paper, horticulture, other industry, and the built environment) and technology (steam turbine, STEG, gas turbine, gas engine).

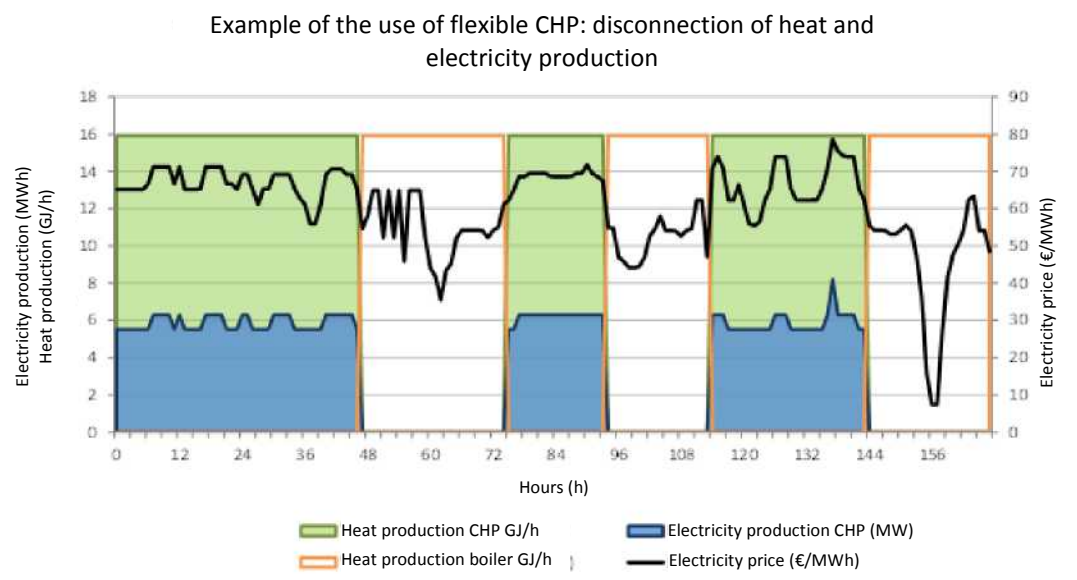
On the basis of information from Energy Matters (2014) a distinction is made between three types of CHP flexibility:

1. *must-run*: have an hourly fixed profile for heat and electricity production;
2. *partial spark-spread*: have an hourly fixed profile for heat production and an accompanying minimum electricity production, in hours with a high electricity price they can produce additional electricity;
3. *spark-spread*: have a fixed hourly heat demand but no restrictions on electricity production, they decide whether to produce the required heat in CHP mode, or pure steam mode or to use a gas boiler. This breaks the connection between heat production and electricity production (see Figure 27).

The horticulture gas engines are also modelled with more flexibility than the 'spark-spread' units: the presence of heat networks and heat buffers means that they have a daily heat demand instead of an hourly heat demand.

In the report we refer to the spark-spread units (including glasshouse horticulture and horticulture) as flexible CHP. We call the must-run and partial spark-spread units must-run units: they have a fixed heat production pattern.

Figure 27 Example of the use of flexible (spark-spread) CHP: when the electricity price is low, the boiler is used for heat production



The main cogeneration parameters of CHP units are shown in Table 16. The units in the table are grouped into particular CHP categories, for the STEG units, for example, these categories depend on the installed electrical capacity.

Table 16 CHP parameters

	Electrical capacity category	Electrical efficiency at full load (no heat supply)	Thermal efficiency	Heat-power ratio
STEG	From 325 MW _e	56%	30%	0.6 : 1
STEG	Between 155 and 325 MW _e	50%	27%	0.6 : 1
STEG	Up to 155 MW _e	48%	34%	0.8 : 1
Gas turbine	From 35 MW _e	35%	50%	1.4 : 1
Gas turbine	Between 16.5 and 35 MW _e	32%	51%	1.6 : 1
Gas turbine	Up to 16.6 MW _e	32%	51%	1.6 : 1
Steam turbine	(all)	28%	62%	2.2 : 1
Gas engine	(all)	42%	45%	1.0 : 1

Source: Jacobs (2008), DNV GL

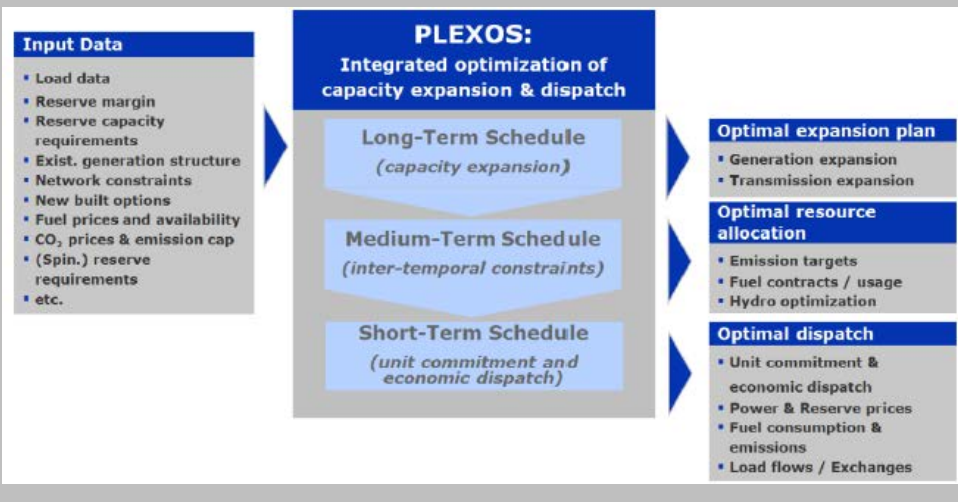
PLEXOS

PLEXOS® is a modelling and simulation software package that provides a robust analytical framework for energy system model builders based on advanced mathematical programming and stochastic optimisation techniques. Important aspects of this model include:

- detailed representation of the various production technologies (incl. CHP and renewable energy);
- modelling of cross-border network with constraints;
- co-optimisation of energy and reserve requirement.

In the last decade, DNV GL developed a market model for the whole European market and used it for many studies and market simulations. For this study the NW-European part of the model will be used to simulate the use of CHP units under various market conditions. In task 2 the model is partly used to evaluate the costs and benefits of the various flexibility options.

The ability to co-optimize the energy and reserve requirement in PLEXOS is very important to predict the electricity prices on the wholesale market and value of the reserve provision. The value of reserve capacity becomes more important as the need for flexibility increases as a result of the growing share of variable renewable energy such as wind and solar energy.



Annex G Cost-effectiveness model

The cost-effectiveness model aims to answer the question of whether CHP installations should remain in operation given the expected variable and fixed maintenance costs, including the reinvestment costs required for many CHP installations. The reinvestment costs are the costs of low-NO_x operation and of a major retrofit.

We use the financial gap models produced by the ECN in 2006-2008 to calculate the MEP subsidies as a cost-effectiveness model. These models are effective and peer-reviewed, the models and the parameters are supported by the sector.

Table 17 shows the parameters used in the model approach and their sources. The table shows that the PLEXOS simulation results are still used for the main parameters for electricity production, heat production and CO₂ costs.

Table 17 Parameters in the cost-effectiveness analysis

Parameter	Unit	Source data
Technique		CHP list (STEG, GT, ST, GM)
Fuel		CHP list
Sector		CHP list
Operating Mode		CHP list (SPR, MR, PSP)
Electrical efficiency	%	CHP list
Maximum Elec. Capacity	MW _e	CHP list
Maximum Heat Capacity	MW _{th}	CHP list
Power-to-Heat Ratio		CHP list
Electricity production	Load factor %	PLEXOS simulation run
	Full-load hours E	PLEXOS simulation run
	Production E/j	PLEXOS simulation run
	Max MW _e /hour	PLEXOS simulation run
Heat production	Load factor %	PLEXOS simulation run
	Full-load hours H	PLEXOS simulation run
	Production H GJ/j	PLEXOS simulation run
	Max GJ/hour	PLEXOS simulation run
Fuel costs	Total/year	PLEXOS simulation run
CO ₂ costs	Total/year	PLEXOS simulation run
Variable O&M costs	Total/year	PLEXOS simulation run
Start costs	Total/year	PLEXOS simulation run

Parameter	Unit	Source data
Investment costs	€/kWe	Investment costs for retrofit/revamp
Retrofitting costs, de-NO _x	€/kWe	Retrofitting costs for de-NO _x (module)
Variable O&M costs	€/kWh	Variable O&M costs
Variable O&M costs, de-NO _x installations	€/kWh	Variable O&M costs de-NO _x
Heat discount	0%	Cost-effectiveness model dashboard
CO ₂ costs heat		Cost-effectiveness model dashboard, calculation for CO ₂ price scenario
Gas price		Cost-effectiveness dashboard, for gas price scenario
Market value of electricity		Calculation: total product over all hourly values
CHP volume equivalent calorific value		Calculation
Economic lifetime	12 years	Fixed value per technology group OT models
Energy content of fuel to be replaced (gas)		Fixed value, FG models (all techniques: natural gas)
Back-up costs of electricity		Fixed value per technology group, FG models
EIA parameters (various)		Fixed value per technology group, FG models
Return on borrowings	6%	Fixed value per technology group, FG models
Return on equity	15%	Fixed value per technology group, FG models
Share of borrowings	80%	Fixed value per technology group FG models
Share of equity	20%	Fixed value per technology group, FG models
Loan at notice	12 years	Fixed value per technology group, FG models
Corporation tax	25%	Fixed value, all technologies

The financial gap models for each technology group also model the net cost for electricity and gas connections, which is quantified slightly differently for each CHP technology group.

Table 17 actually shows three groups of parameters: cost parameters for the investment costs, operational parameters for the income from electricity and heat, maintenance costs, and other parameters including the business case parameters (financial: including equity/borrowing ratio and required return on equity).

The investment cost levels from Jacobs (2008) are used as a basis for the investment costs module for the regular refit/revamp. This produces a typical value of 25%. The retrofit costs for low NO_x companies are collected by CE Delft. All costs are collected for several size categories of installation and are scaled according to the size of the simulated unit.

The basic principles for the interest rate and the shares of equity and borrowings are in line with the values used for SDE calculations up to 2008.⁴⁸ The assumption here is that, when financing a business, a return on equity of 15% is a criterion for a positive assessment of a project. This must take into account the stricter requirements set for secondary activities (such as CHP installations) in industry.

The operational aspects are simulated in the PLEXOS modelling environment. The simulation of the CHP installation in the PLEXOS model produces the spot market electricity price for each year. PLEXOS also provides, for each of the 131 simulated CHP installations, per unit and per hour:

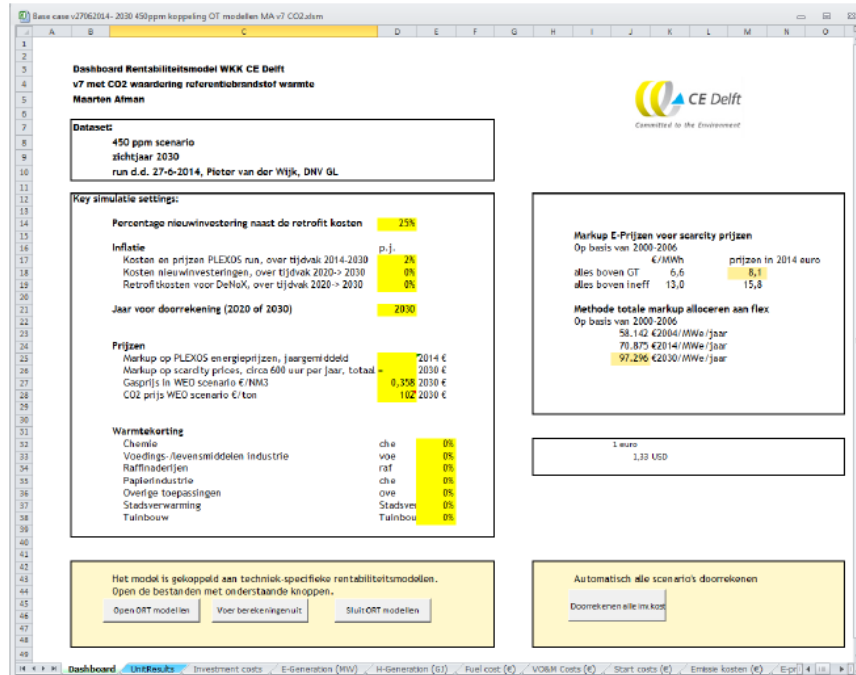
- income from electricity;
- income from heat;
- variable maintenance and operating costs;
- CO₂ costs.

All these data for each simulation are exported from the PLEXOS model after a PLEXOS simulation run, and entered into the profitability model. The financial gap can then be calculated for each simulated unit with the profitability model.

Figure 28 shows the 'Dashboard' of the profitability model. The main parameters, which differ between simulation runs, can be selected here.

⁴⁸ See: (ECN, 2008)

Figure 28 CE Delft cost-effectiveness model dashboard



Key:	
Dashboard Rentabiliteitsmodel WKK CE Delft	CE Delft CHP Cost-Effectiveness Model Dashboard
v7 met CO ₂ waardering referentiebrandstof warmte	v7 with CO ₂ valuation of reference fuel for heat
zichtjaar 2030	reference year 2030
Key simulatie settings	Key simulation settings
Percentage nieuwinvestering naast de retrofit kosten	Percentage of new investment in addition to retrofit costs
Inflatie	Inflation
Kosten en prijzen PLEXOS run over tijdvak	Costs and prices PLEXOS run over period
Kosten nieuwinvesteringen, over tijdvak	Costs of new investment over period
Retrofitkosten voor DeNo _x , over tijdvak	Retrofit costs for DeNo _x over period
Jaar voor doorrekening (2020 of 2030)	Charging year (2020 or 2030)
Prijzen	Prices
Markup op PLEXOS energieprijzen, jaargemiddeld	Mark-up on PLEXOS energy prices, annual average
Markup op scarcity prices, circa 600 uur per jaar, totaal	Mark-up on scarcity prices, circa 600 hours a year, total
Gasprijs in WEO scenario €/NM3	Gas price in WEO scenario €/NM3
CO ₂ prijs WEO scenario €/ton	CO ₂ price WEO scenario €/t
Warmtekorting	Heat discount
Chemie	Chemicals
Voedings-/levensmiddelen industrie	Food industry
Raffinaderijen	Refineries
Papierindustrie	Paper industry
Overige toepassingen	Other applications
Stadsverwarming	District heating
Tuinbouw	Horticulture
Markup E-Prijzen voor scarcity prijzen	Electricity price mark-up on scarcity prices
Op basis van 2000-2006	On basis of 2000-2006

prijzen in 2014 euro	prices in 2014, euros
alles boven GT	everything above GT
alles boven ineff	everything above ineff
Methode totale markup alloceren aan flex MWe/jaar	Method for allocating total mark-up to flex MWe/year
Het model is gekoppeld aan techniek-specifieke rentabiliteitsmodellen. Open de bestanden met onderstaande knoppen.	The model is linked to technology-specific cost-effectiveness models. Open the databases with the buttons below.
Open ORT modellen	Open FG models
Voer berekeningenuit	Carry out calculations
Sluit ORT modellen	Close FG models
Automatisch alle scenario's doorrekenen	Calculate all scenarios automatically
Doorrekenenalleinv.kost	Calculateallinv.cost
VO&M	VO&M
Emissie kosten	Emission costs

The cost-effectiveness model is linked to adapted financial gap models of the ECN.

A cost-effectiveness calculation is carried out for each simulated CHP unit. As a result of the differences between the lifetime, efficiency, technology and configuration of the simulated units, the efficiency of various units differs, even within the same broader technology group.

A histogram has therefore been chosen to visualise the results. We group the CHP units by technology according to their cost-effectiveness, thus creating a number of cost-effectiveness ranges and then count the number of units within that range. The numbers for each cost-effectiveness range (frequency) can be represented in a graph.

Annex J contains all of the results, for all technology groups, for all reference years/scenarios.

Annex H Electricity market in the scenarios

The simulation modelling for the NW-European market shows how much electricity the different production units produce and how much is imported/exported. This is illustrated for 2012, for the baseline scenario in 2020, and for four scenarios in 2030.

This annex describes the results of the simulation model, which are represented in three ways:

1. Composition of the production market. We show the scale of the production facilities, broken down by main type, total demand, import and export and the average number of operating hours per type of installation.
2. Residual demand-duration curve. This curve shows the residual market demand for electricity after deducting the supply of renewable energy, and thus the extent of the demand to be met by residual energy. This is represented as a curve over the year, showing the amount of the residual demand per hour.
3. The electricity price. This is also represented as a curve over the year.

Conclusions per scenario:

2012:

In 2012 the shares of renewable energy, wind and solar are limited. Virtually all gas-fired power stations have been shut down, coal-fired power stations are running at full capacity. There are substantial imports. The residual demand over the whole year is more than 7 GWe.

2020:

The proportion of wind and solar is higher than in 2012. In 2020 also, almost all gas-fired power stations have been shut down and coal-fired power stations are running at full capacity. Imports have grown. Flexible CHP power stations are operating for an average of 5 500 hours.

2030 - baseline scenario:

In 2030 the shares of wind and solar have increased even further. Prices have risen as a result of rising demand and the shut-down of residual capacity. Gas-fired power stations are running for an average of 1 900 operating hours. Flexible CHP power stations have an average of 6 500 operating hours.

2030 - high CO₂ price:

In this scenario the production capacities have remained the same as in the baseline scenario. There is a shift from coal to gas-fired power stations: gas-fired power stations are operating for many hours, coal-fired power stations for slightly fewer. The electricity prices are considerably higher at around € 75/MWh.

2030 - low CO₂ price:

The results of this scenario are very similar to those of the baseline scenario. This is because the fuel and CO₂ prices are virtually the same.

2030 – High renewable:

In this scenario the share of renewable energy has grown significantly. The residual demand-duration curve shows that the residual demand is slightly lower and there are periods of surplus when there is no demand for residual capacity.

The prices are on average lower than in the baseline scenario, and for ca 600 hours they are below € 20/MWh. The position of flexible CHP is not quite as good as in the baseline scenario: nearly 5 200 operating hours on average. Normal gas-fired power stations operate for fewer than 250 hours.

The striking point in all the scenarios is that all years have net imports. In 2012 and 2020 imports are around 24-25 TWh, in 2030 they have fallen to 10 TWh.

Gas-fired power stations operate for a small number of hours in most of the scenarios. Only in the high CO₂ prices scenario do they operate for more hours than coal-fired power stations. This shows that gas-fired power stations are in a difficult position in the electricity market.

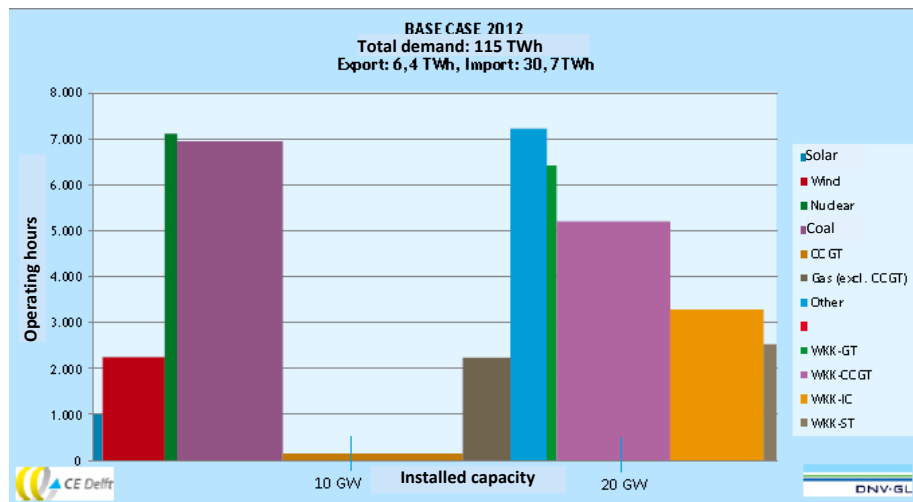
Supply and demand for electricity

Notes:

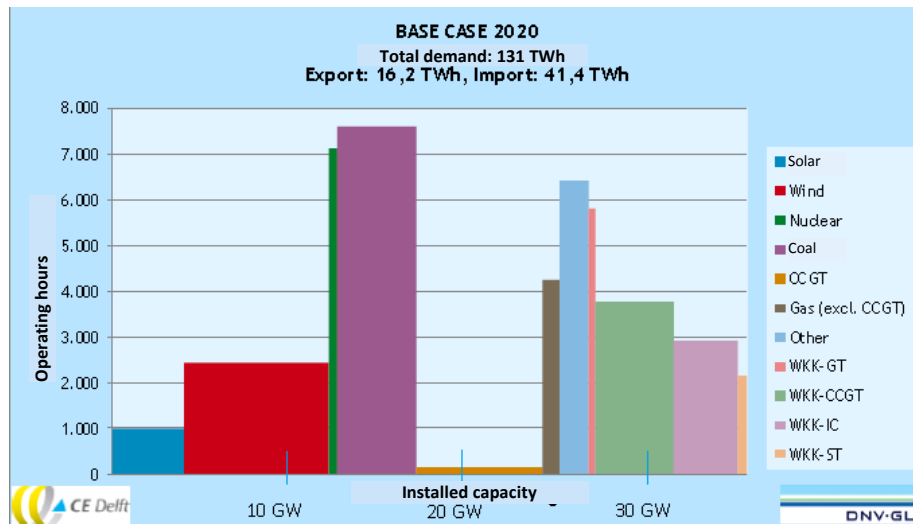
The figures show the installed production capacity horizontally, and the number of operating hours vertically. The renewable options (solar and wind) are on the left and the CHP installations on the right. The other fossil production units are in the middle. The abbreviations in the key have the following meanings:

CC GT	= gas-fired power stations
WKK-GT	= CHP gas turbine
WKK - CCGT	= STEG
WKK - IC	= Gas engine
WKK - ST	= Steam turbine

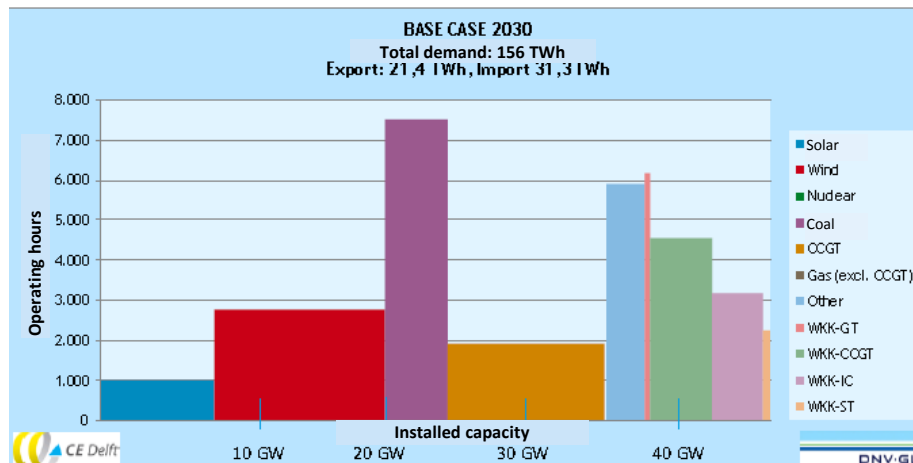
1. 2012



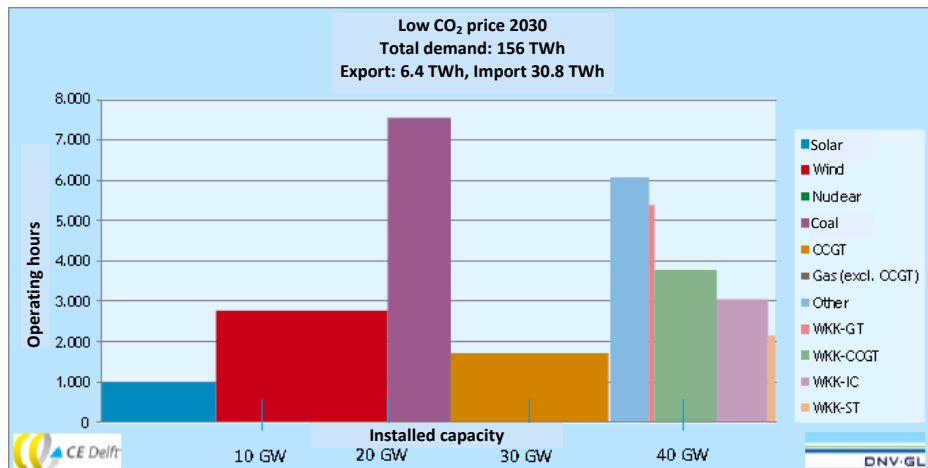
2. 2020 – Baseline scenario



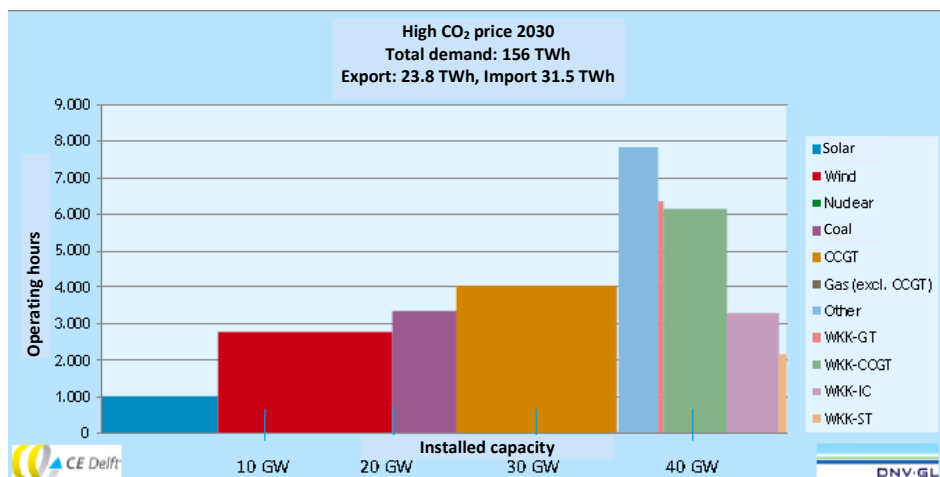
3. 2030 – Baseline scenario



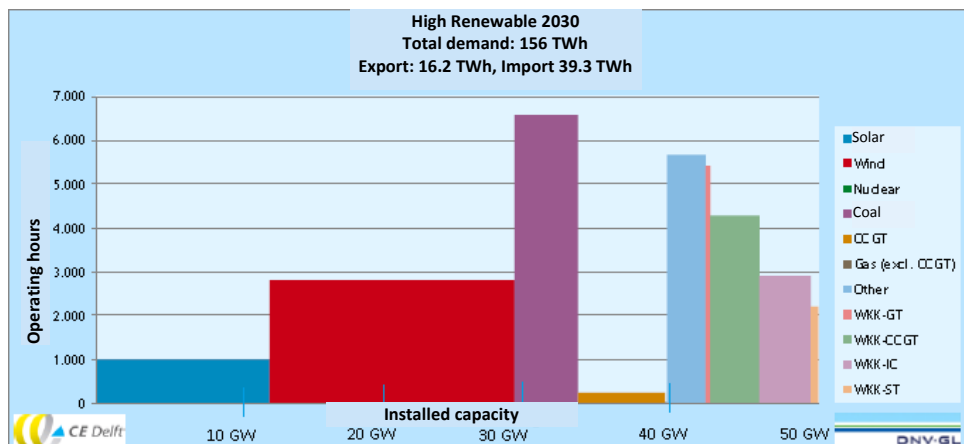
4. 2030 - Low CO₂ price scenario



5. 2030 - High CO₂ price scenario



6. 2030 - High renewable



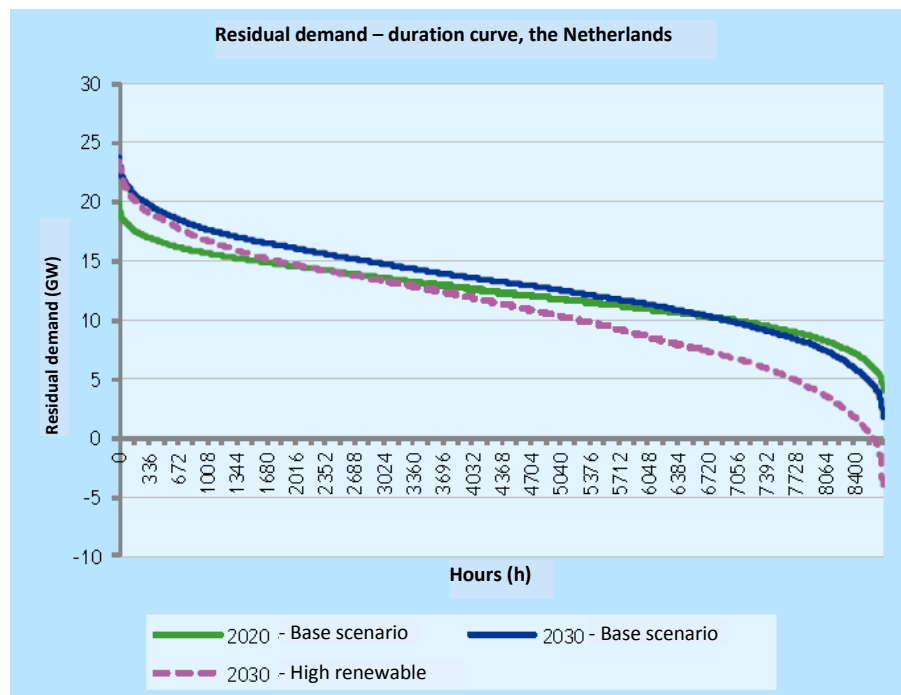
Residual electricity demand

The resulting fossil generation profile can be represented in a 'residual electricity demand' curve. This shows the electricity demand met by

conventional capacity: the hourly demand minus the supply of wind and solar energy.

Figure 29 shows the residual demand for the different scenarios. Figure 29 shows that the residual demand is higher in 2030 than in 2020: the electricity demand has grown faster than the supply of renewable energy. As a result, the possible market share for CHP units in 2030 is bigger than in 2020. The residual demand shows the size of the market remaining after deducting the sustainable production from the demand. This residual demand is met by the market: the domestic production and foreign production via import-export differences. In the high renewable scenario the share of renewable energy increases so much that the market share for conventional generation is lower than in the 2020 and 2030 baseline scenarios. There are even hours in which the supply of renewable energy exceeds electricity demand.

Figure 29 Residual demand-duration curve for the various scenarios: 2012-Baseline, 2020-Baseline, 2030-Baseline (& high CO₂ price & low CO₂ price), and 2030 - high renewable



Electricity prices

The electricity prices are influenced by factors such as the market share of conventional generation and by fuel prices.

Figure 30 shows the price-duration curves of the various scenarios for 2030⁴⁹. In the 'high renewable' scenario the prices are lower than in the baseline scenario because of the increase in renewable energy and the resulting smaller market share for conventional generation (fuel prices are based on the IEA New Policies scenario in both cases). The result is that

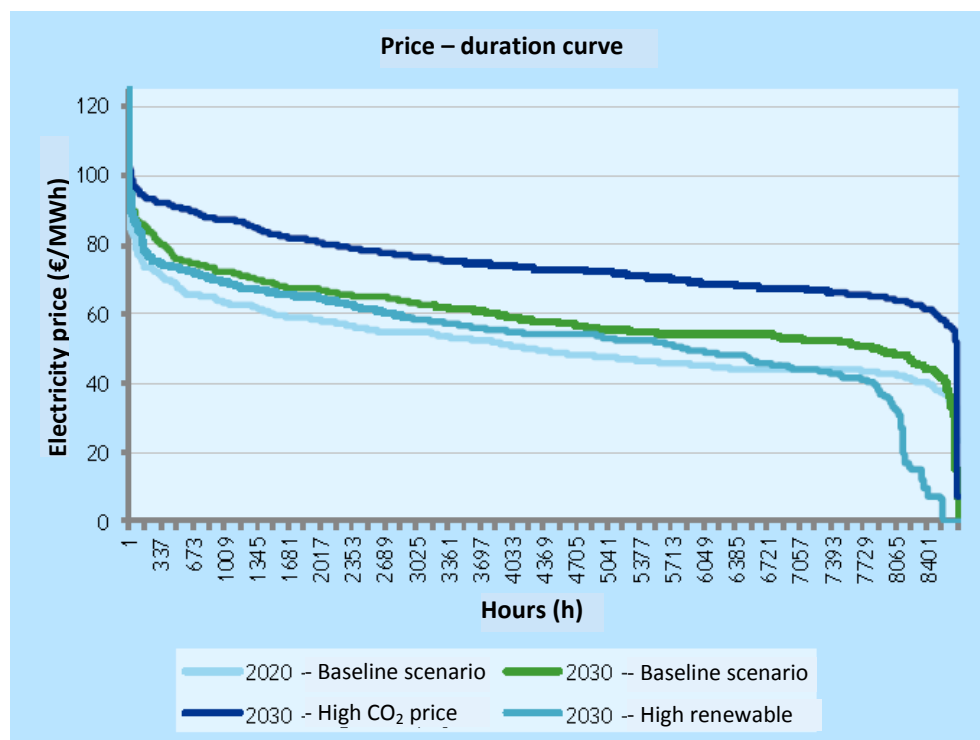
⁴⁹ The electricity price is defined in PLEXOS on the basis of the marginal costs of the cheapest unit operating at part load (in other words the marginal unit).

income from the electricity market is also lower for CHP power stations. At the same time, the gas price remains the same in this scenario as in the baseline scenario, so the CHP installations have a poorer spark-spread (the ratio between the electricity and gas price).

In the high CO₂ price scenario, a ‘gas for coal’ situation has been created by the much higher CO₂ credit price (€ 71/MT CO₂). The high CO₂ price has also resulted in a higher electricity price than in the baseline scenario and fewer extremely low electricity prices: more gas-fired power stations are used and so there is more flexibility available in the system.

The prices in the Current Policies scenario do not differ substantially from the baseline scenario: the fuel prices are somewhat higher than in the 2030- Baseline (NP) scenario but the CO₂ credit prices are slightly lower (the share of renewable energy is the same).

Figure 30 Electricity price-duration curves for the Netherlands for the various scenarios for 2030



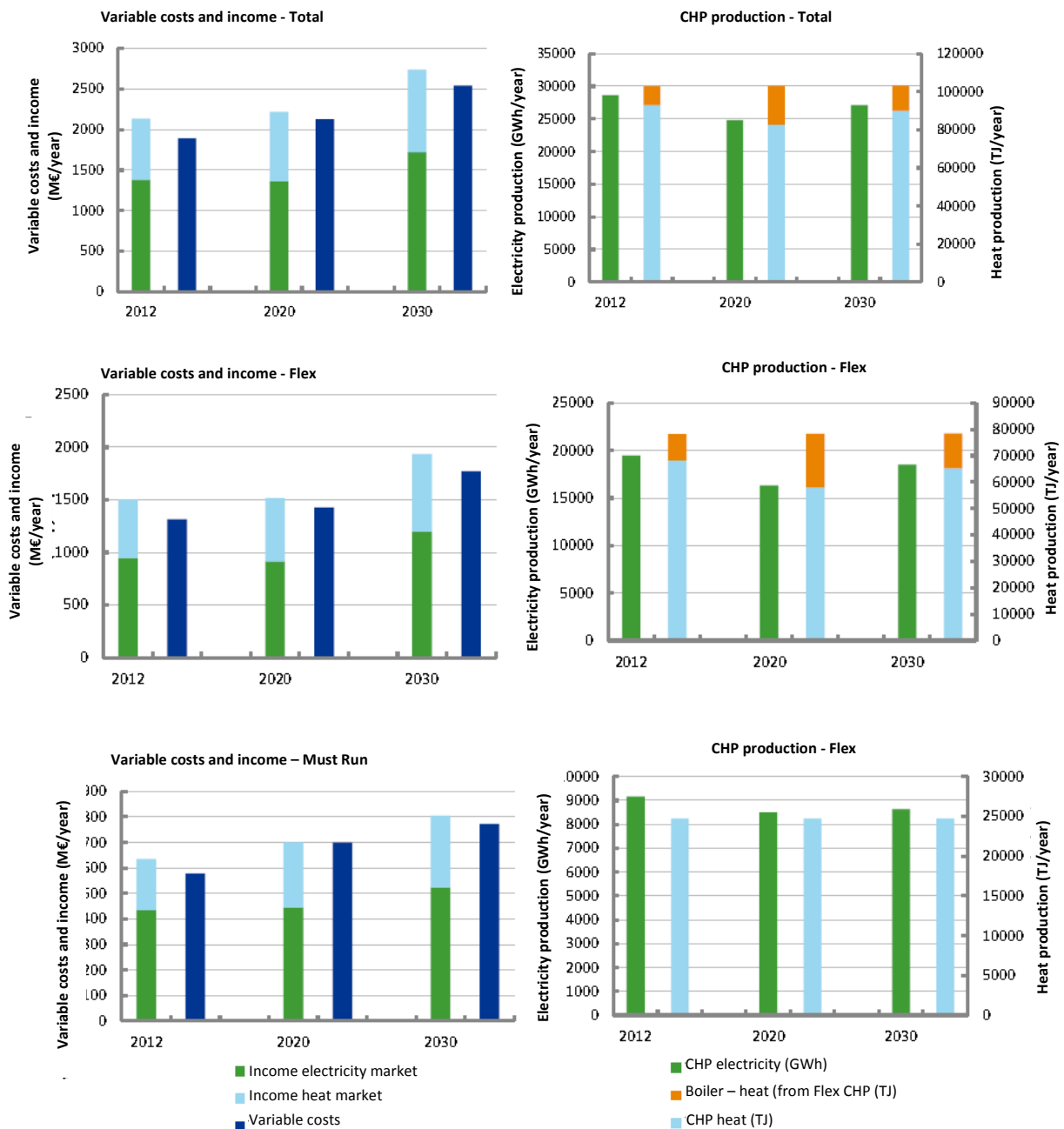
Annex I **Market position of CHP units on the basis of variable costs/benefits**

Variable costs/benefits of CHP installations in the 2020/2030 baseline scenario

The variable costs and benefits of the CHP units were determined on the basis of the North-West-European simulation model. The variable costs comprise the fuel costs, start-up costs, emission costs and the variable maintenance and operating costs. The variable benefits are the income from the sale of electricity and the sale of heat.⁵⁰ The difference between the variable costs and benefits, in other words the variable net benefits, gives an initial indication of the efficiency of the CHP units.

⁵⁰ The electricity price is calculated by the simulation model and is the marginal cost price of a marginal power station. This electricity price is determined by system optimisation and does not incorporate strategic behaviour. The heat price is treated as equivalent to the heat costs avoided by having used a boiler with 90% efficiency (including emission costs avoided).

Figure 31 The variable costs and income and the heat and electricity production of the CHP power stations in industry and greenhouse horticulture in the Netherlands



The top graphs show the results for the total of industrial CHP facilities and greenhouse horticulture. The middle graphs show the results for flexible CHP. The bottom graphs show the results for the must-run CHP power stations.

'Income electricity market' is the income from the sale of electricity. 'Income heat market' is the benefits from the sale of heat. 'Variable costs' comprise fuel costs, emission costs, start-up costs and variable maintenance and operating costs; it does not include fixed costs. 'CHP electricity' and 'CHP heat' are respectively the electricity and heat (steam) produced in CHP mode (cogeneration of heat and electricity). 'Boiler heat (from Flex CHP)' is the amount of heat produced by gas boilers in flexible CHPs or by flexible CHPs in pure steam mode.

The variable costs and benefits are reproduced in Figure 31. As they depend on the electricity and heat production of the CHP, production is also represented in Figure 31. Figure 31 shows the results for the CHP facilities in general, for flexible CHP units and must-run CHP units. The absolute differences between the must-run and flexible CHP are partly a result of the differences in the installed capacity and are therefore difficult to compare.

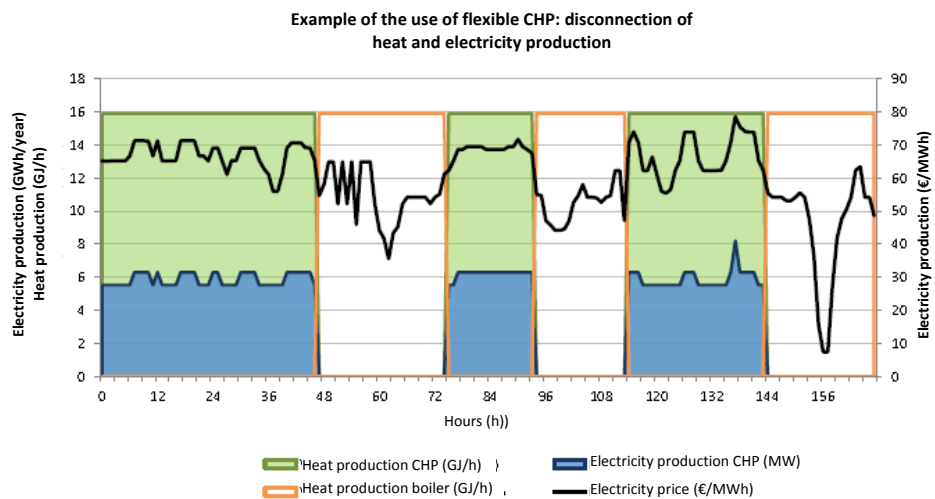
It can be seen that less electricity and heat will be produced by the CHP in 2020. The increase in renewable energy at home and abroad reduces the market share for CHP production and the margins. The larger gas-coal price spread in 2020 further reduces the margins for CHP units. Thus the electricity production of 'must-run' units falls as a result of lower margins in 2020. The reduced heat production of flexible CHP is counterbalanced by a larger amount of heat production in gas boilers.

In 2030 the cogeneration of electricity and heat by flexible CHP units is higher again than in 2020: the market for CHP production has grown as a result of reduced imports from Germany (phasing-out of coal (lignite) - fired power stations and nuclear power stations in Germany). The growth of renewable energy (which reduces the market share of CHP) is compensated for partly by the increase in the electricity demand resulting from further electrification.

The result of the developments described above is that the net variable benefits of all of the CHP capacity have shrunk in 2020 in comparison with 2012 but have grown again slightly in 2030 (although they are still below the 2012 level). Note that in 2020 and 2030 the benefits and costs are higher because the fuel prices are higher than in the preceding years: this pushes up the costs, but also the heat price and the electricity price.

The flexible CHP units have relatively higher net benefits than the must-run CHP units in all three of the reference years. Breaking the connection between the heat and electricity production in flexible CHP units allows them to choose to generate heat with an efficient boiler in hours when the electricity prices are low so that they are not making a loss during these hours (see Figure 32). The must-run units must produce heat with the CHP unit during these hours and so sell their electricity at a loss. In 2020 in particular, the advantage of this flexibility is clear: the flexible CHP units have positive net benefits while the must-run CHPs do not benefit from this. It should be noted that these net benefits do not include fixed costs such as depreciation (for this, see the results of the cost-effectiveness model).

Figure 32 Example of the use of flexible CHP: at a low electricity price the boiler is used for heat production



Variable costs/benefits CHP installations in other scenarios

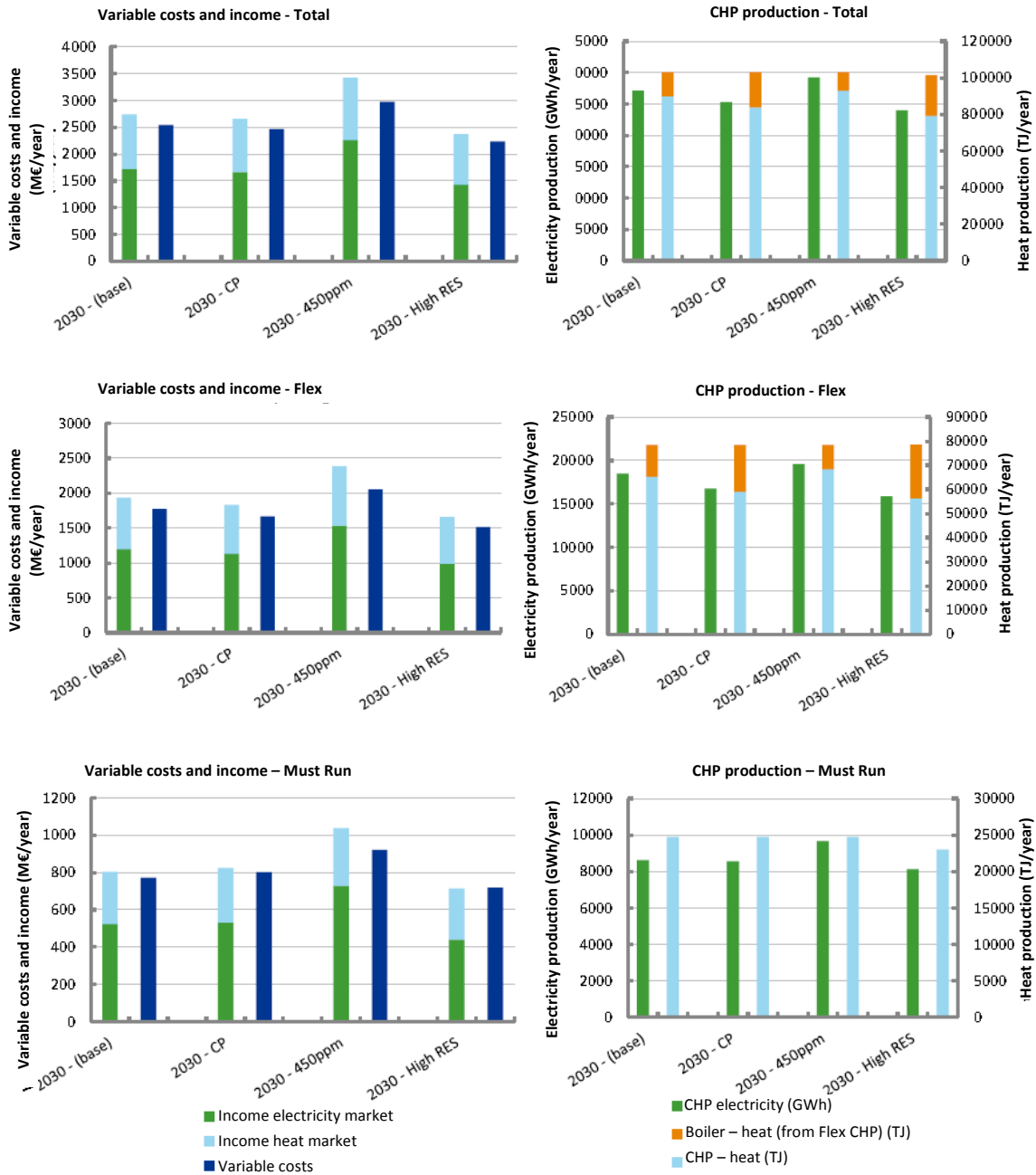
Figure 33 shows the effect of a higher gas price (2030 low CO₂ price scenario), a gas-for-coal exchange in the ranking (2030 high CO₂ price scenario) and increased sustainability of the electricity mix (2030 'high renewable'). The high CO₂ price and the Green Revolution scenario paint a different picture of the CHP position from the baseline scenario (the 2030 Baseline (NP) scenario).

In the high CO₂ price scenario the CO₂ price is so high that the price difference between electricity from gas- and coal-fired power stations is minimal: efficient STEG power stations are even cheaper than coal-fired power stations. The result of this high CO₂ price is that the electricity price is also a lot higher than in the 2030 baseline scenario. The CHP units therefore produce more electricity and earn more per MWh electricity. The 2030 high CO₂ price scenario is the scenario with the largest net variable benefits for all CHP units.

The 'high renewable' scenario paints the opposite picture. Further penetration of renewable energy leaves less scope for conventional units (including CHP) on the electricity market and the electricity price also drops. The flexibility of the flexible CHP units still gives them positive net variable benefits (although lower than in the baseline scenario). But the benefits of the must-run units are reduced⁵¹.

⁵¹ Electricity and heat production of must-run units is lower as the most loss-making units have been shut down in the period leading up to 2030.

Figure 33 Results of the sensitivity scenarios, including the 2030 baseline scenario for reference



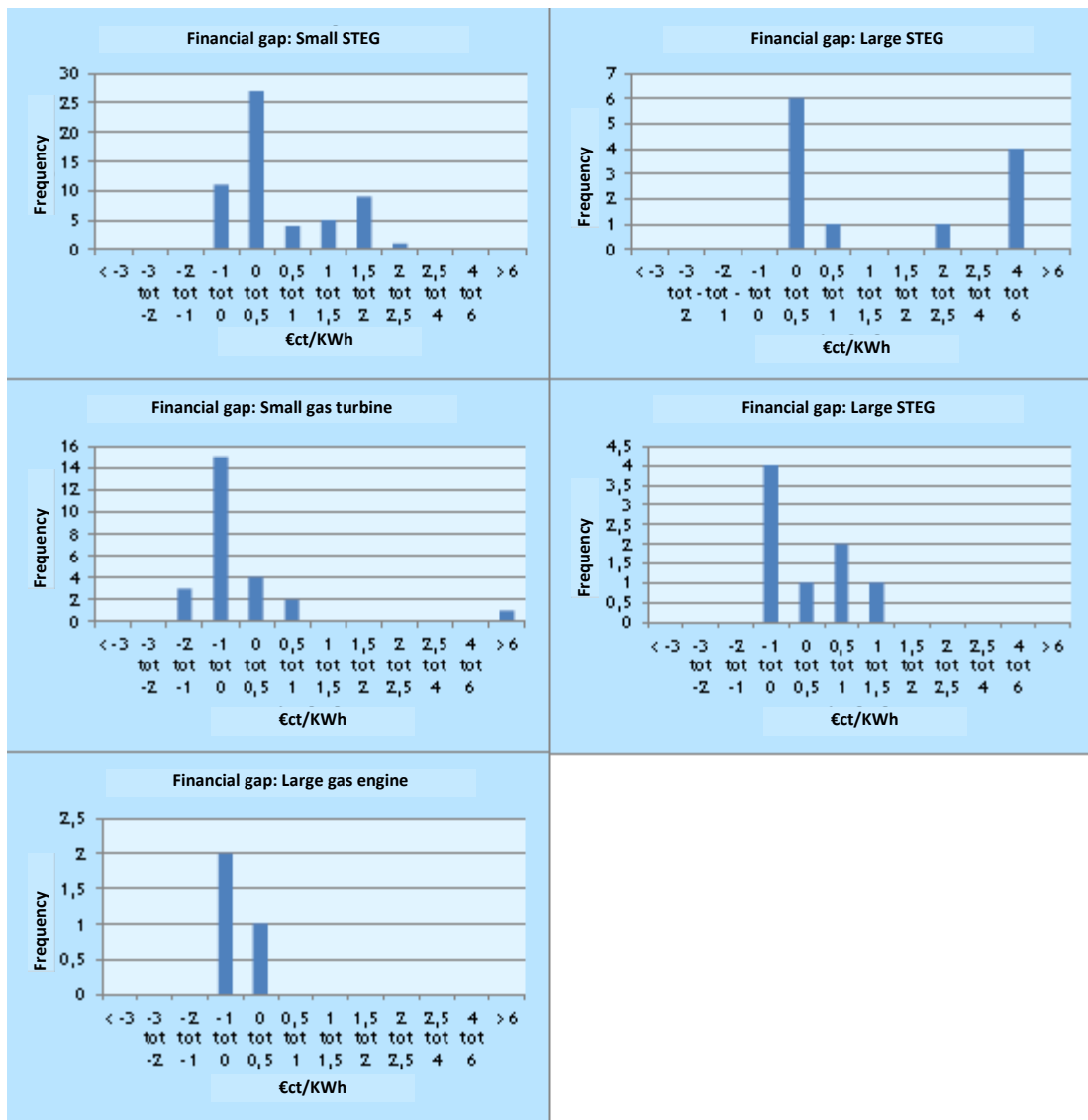
Annex J Results of the modelling of the cost-effectiveness model

J.1 Baseline scenario 2020

The figures show the financial gap of CHP installations per type in 2020. The calculation includes:

- investments for retrofit costs to comply with NO_x requirements;
- new investment costs of 35% to 0% for all types.

The histograms for 2020 below are for the 25% case, those on the next page are for the sensitivity to 25%.

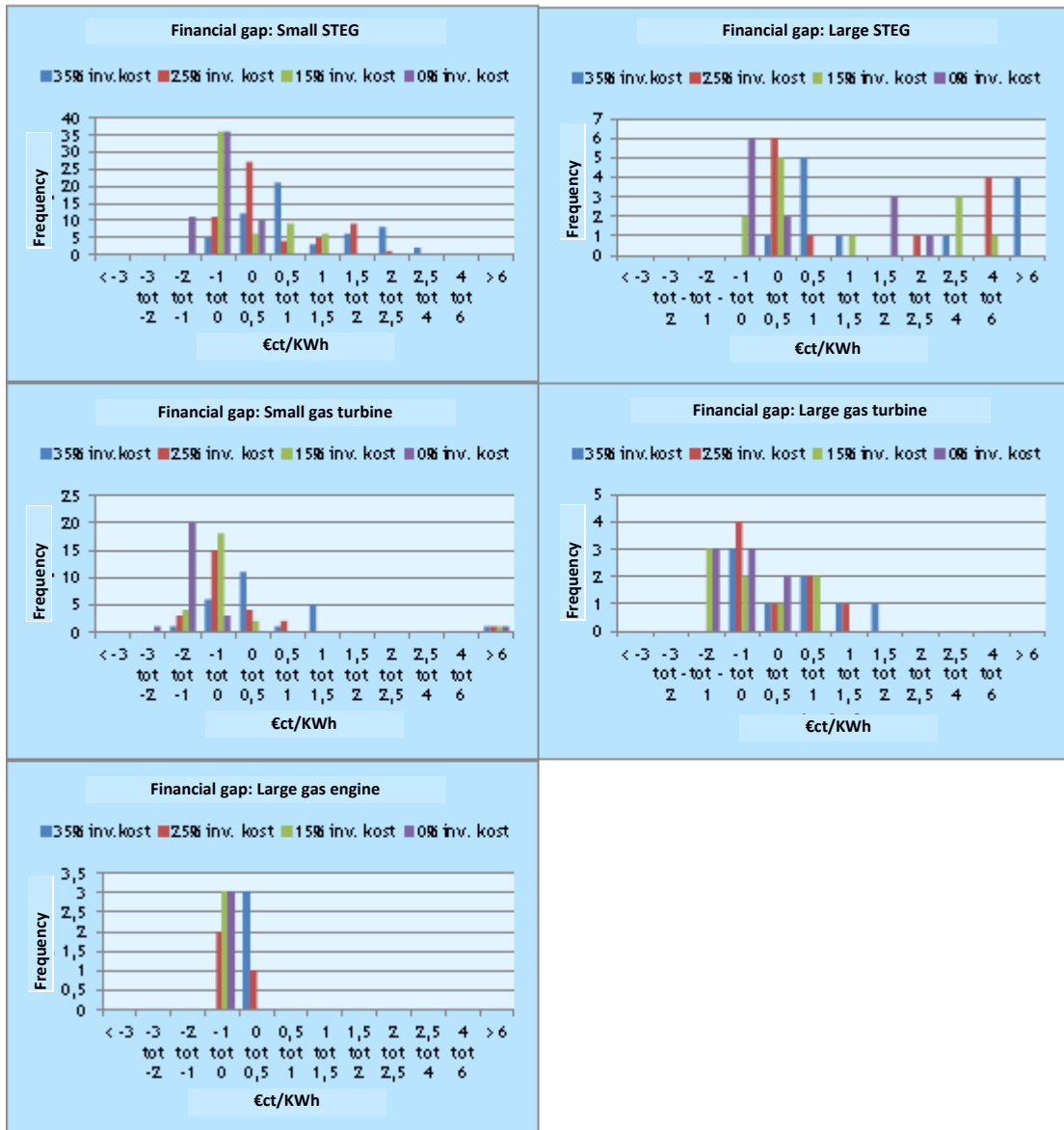


Key:
tot = to

Sensitivity to the scale of the investment costs.

In the previous calculations of the financial gap 25% of new investment costs are included in addition to the retrofit costs for compliance with NO_x-emission requirements.

The graphs below show how the financial gaps change if another percentage is chosen instead of 25%.



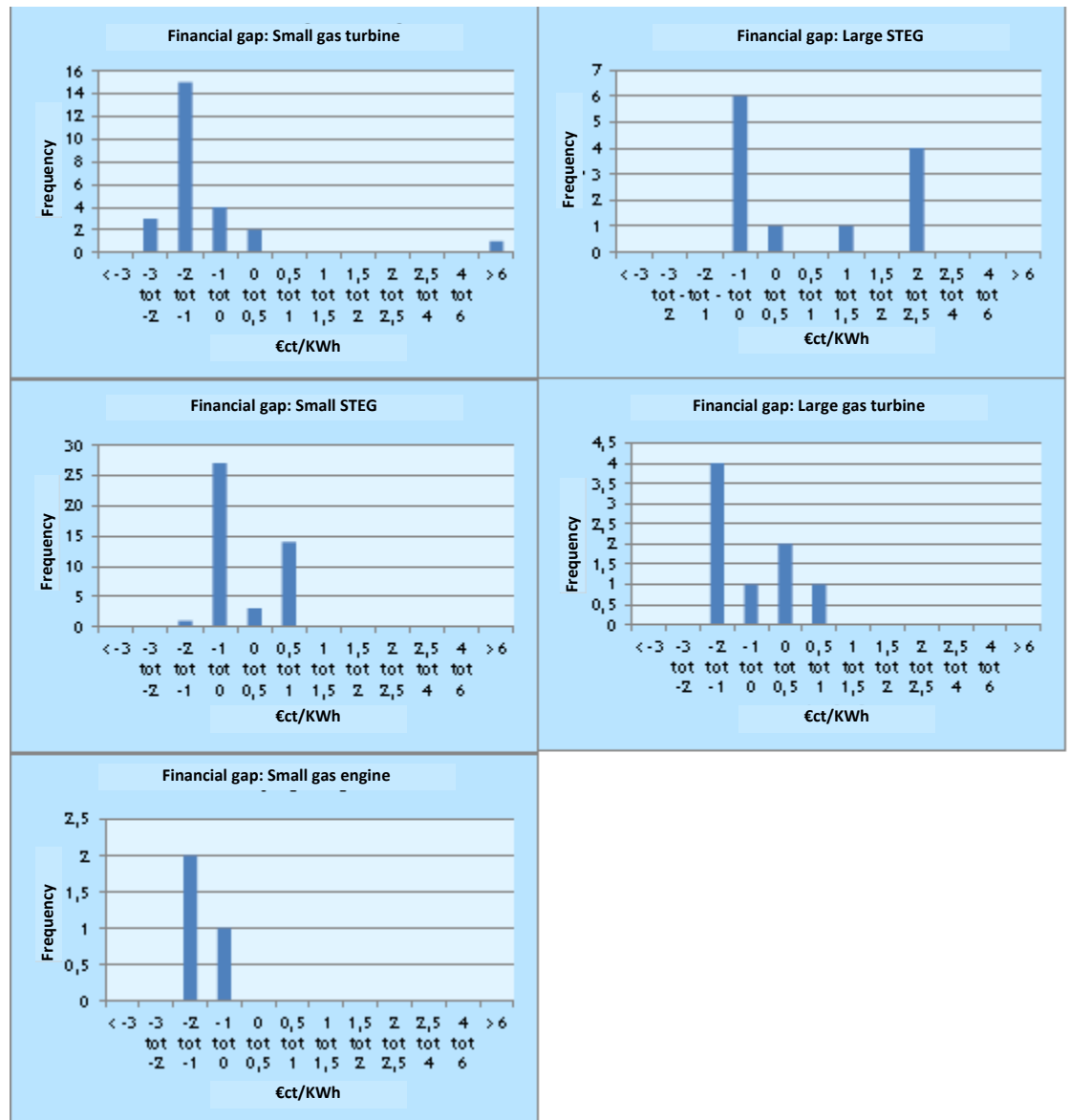
Key:
 inv. kost = investment cost
 tot = to

J.2 Baseline scenario 2030

The figures show the financial gap of the CHP installations per type in 2030. The calculation takes account of:

- investments for retrofit costs to comply with NO_x requirements;
- new investment costs of 35% to 0% for all types.

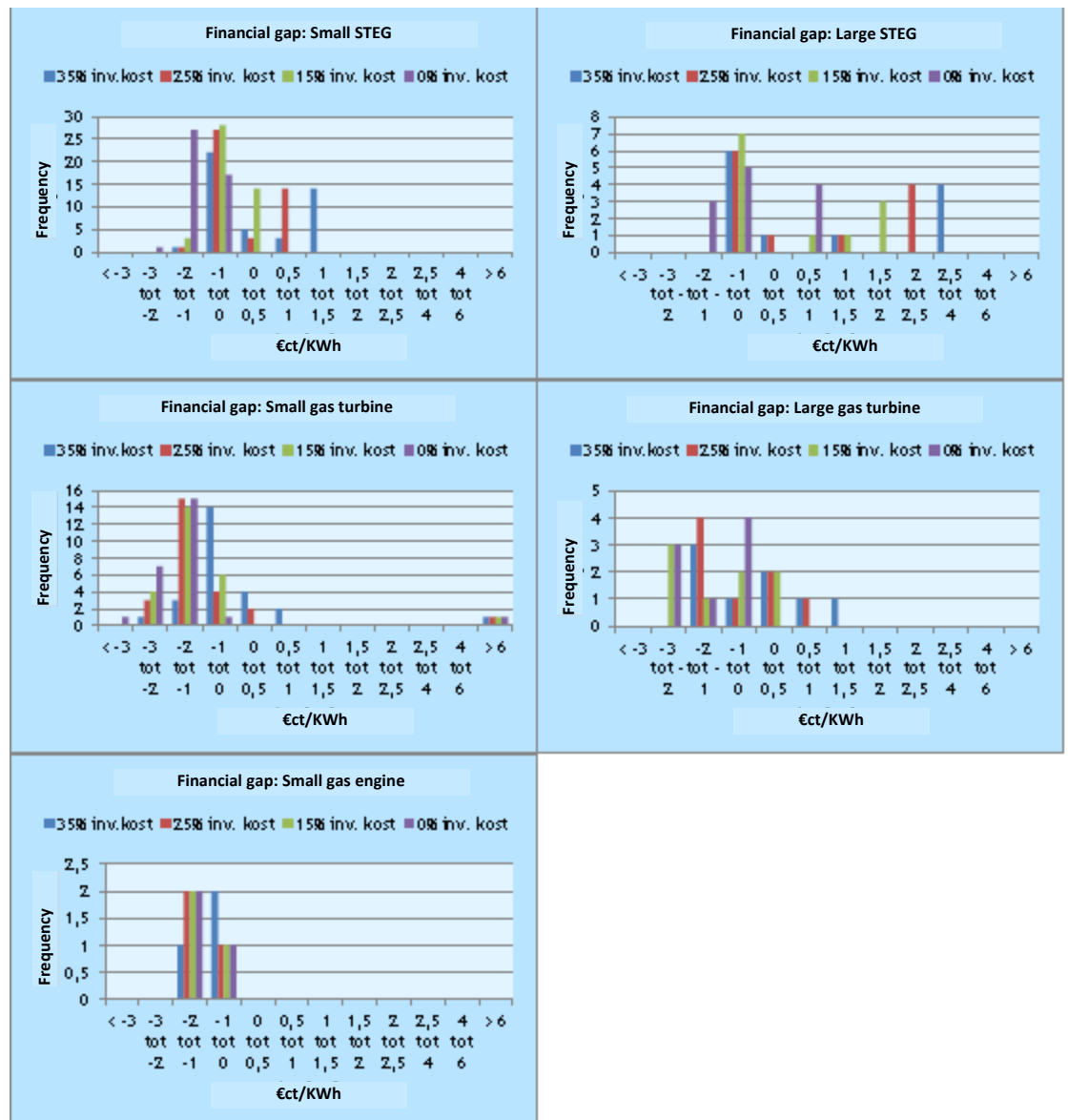
The histograms for 2020 below are for the 25% case, those on the next page are for the sensitivity to 25%



Key:
tot = to

Including sensitivity for 25% new investment costs in the minimum retrofit costs

The graphs below show the financial gaps depending on the scale of the investment costs.



Key:
 inv. kosten = investment costs
 tot = to

J.3 2030 - High CO₂ prices

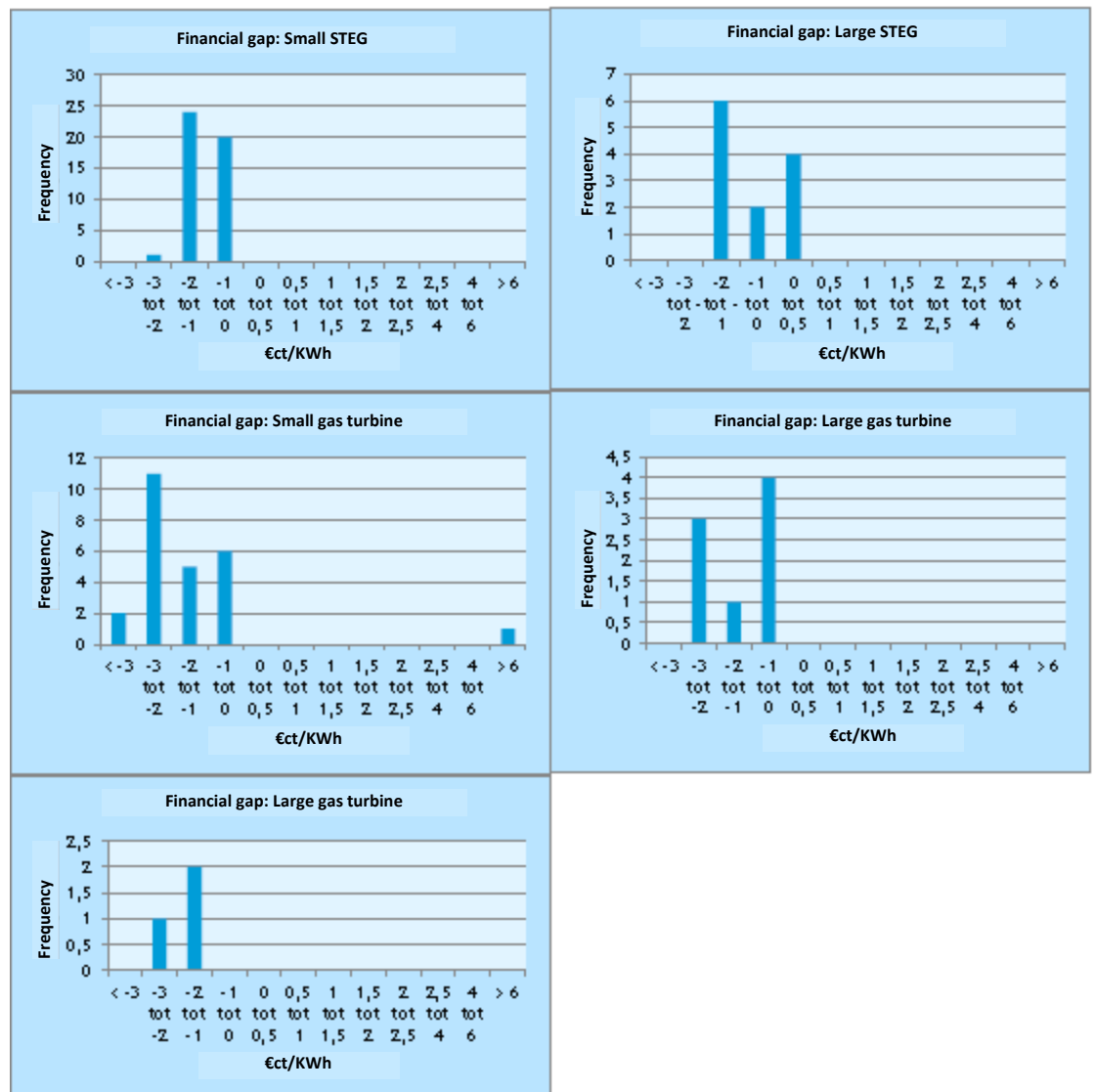
The figures show the financial gap of the CHP installations per type in 2030. The calculation takes account of:

- investments for retrofit costs to comply with NO_x requirements;
- new investment costs of 35% to 0% for all types.

The histograms for 2030 below are for the 25% case, those on the next page are for the sensitivity to 25%.

The gas price € 7.2/GJ in 2012 euros still corrected for inflation by 2% -> € 0.358/nm³ in 2030.

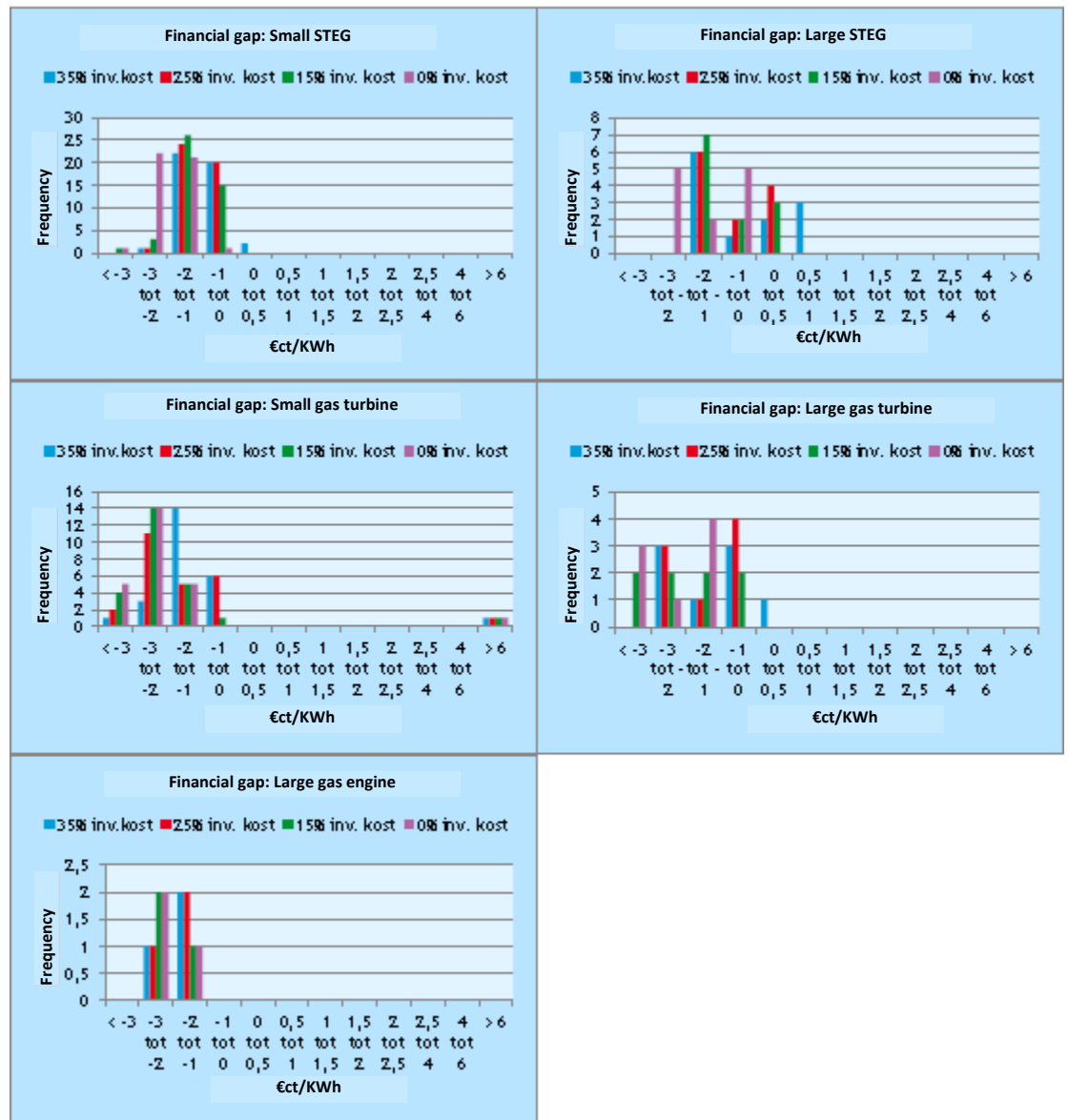
CO₂ costs € 71.43/Mt in 2012 euros; corrected for inflation by 2% = € 102/Mt in 2030.



Key:
tot = to

Including sensitivity for 25% new investment costs in the minimum retrofit costs

The graphs below show the financial gaps depending on the scale of the investment costs



Key:
 inv. kosten = investment costs
 tot = to

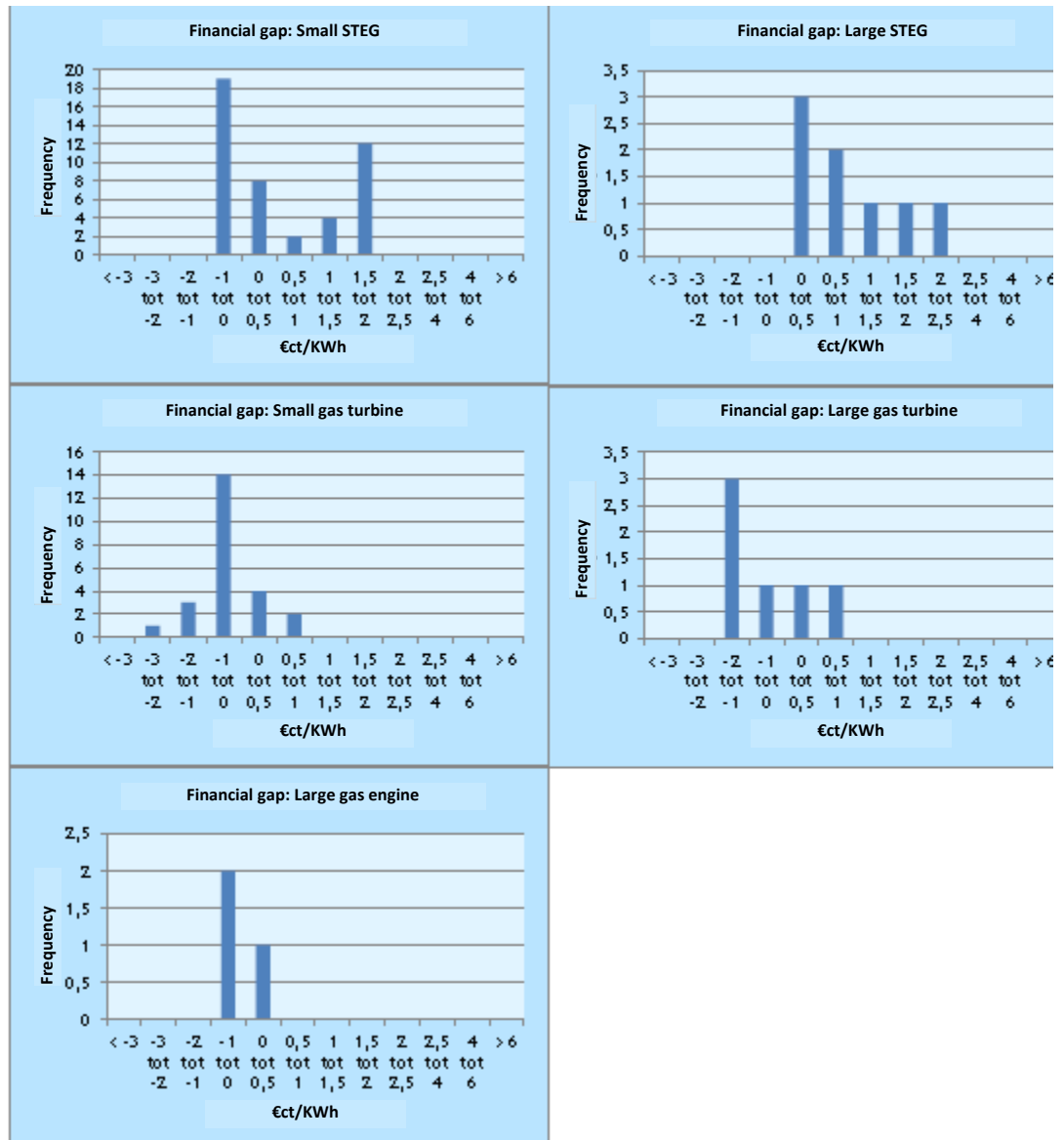
J.4

2030 - High renewable

The figures show the financial gap of the CHP installations, per type in 2030. The calculation takes account of:

- investments for retrofit costs to comply with NO_x requirements;
- new investment costs of 35% to 0% for all types.

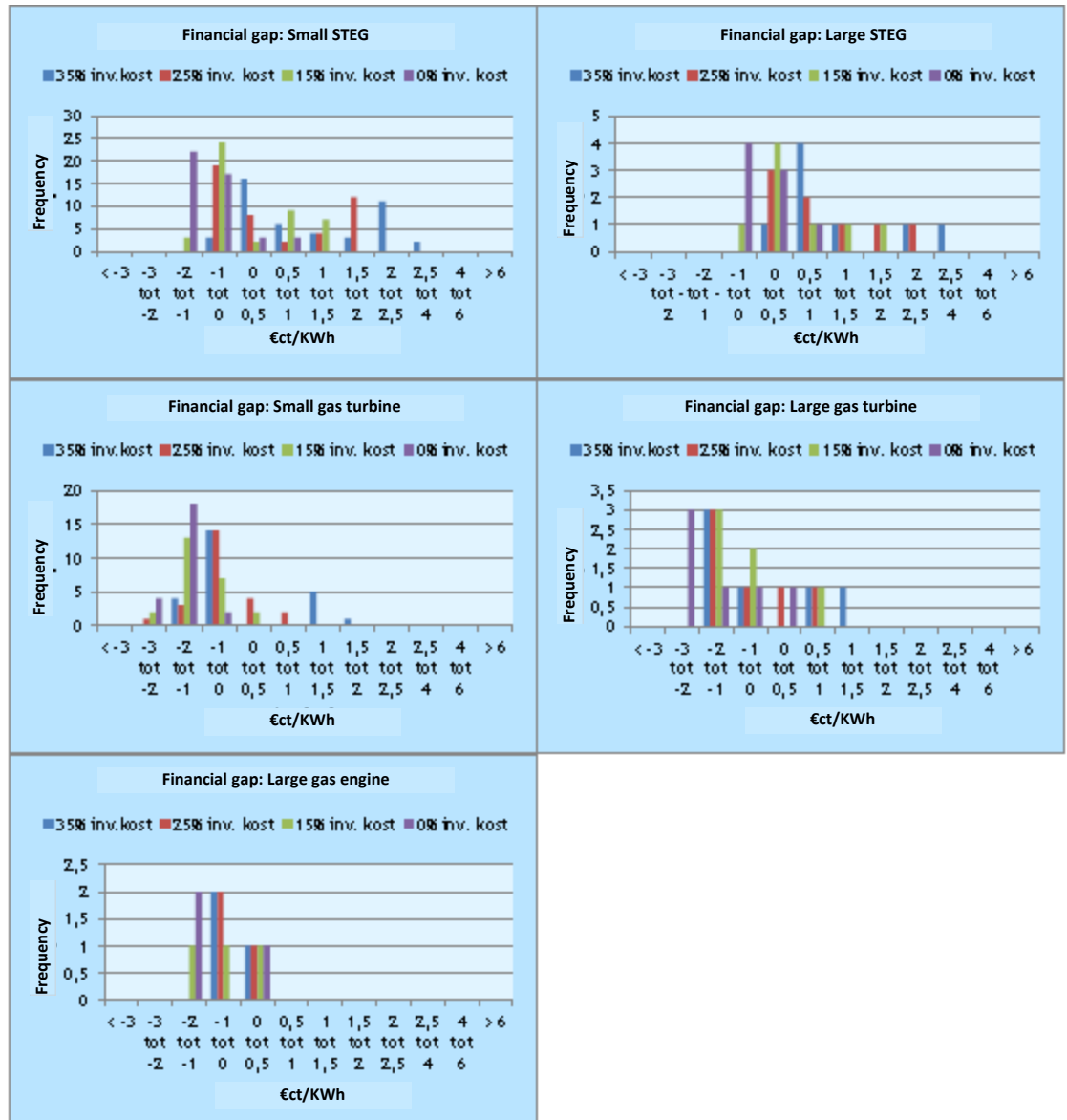
The histograms for 2020 below are for the 25% case, those on the next page are for the sensitivity to 25%.



Key:
tot = to

Including sensitivity for 25% new investment costs in the minimum retrofit costs

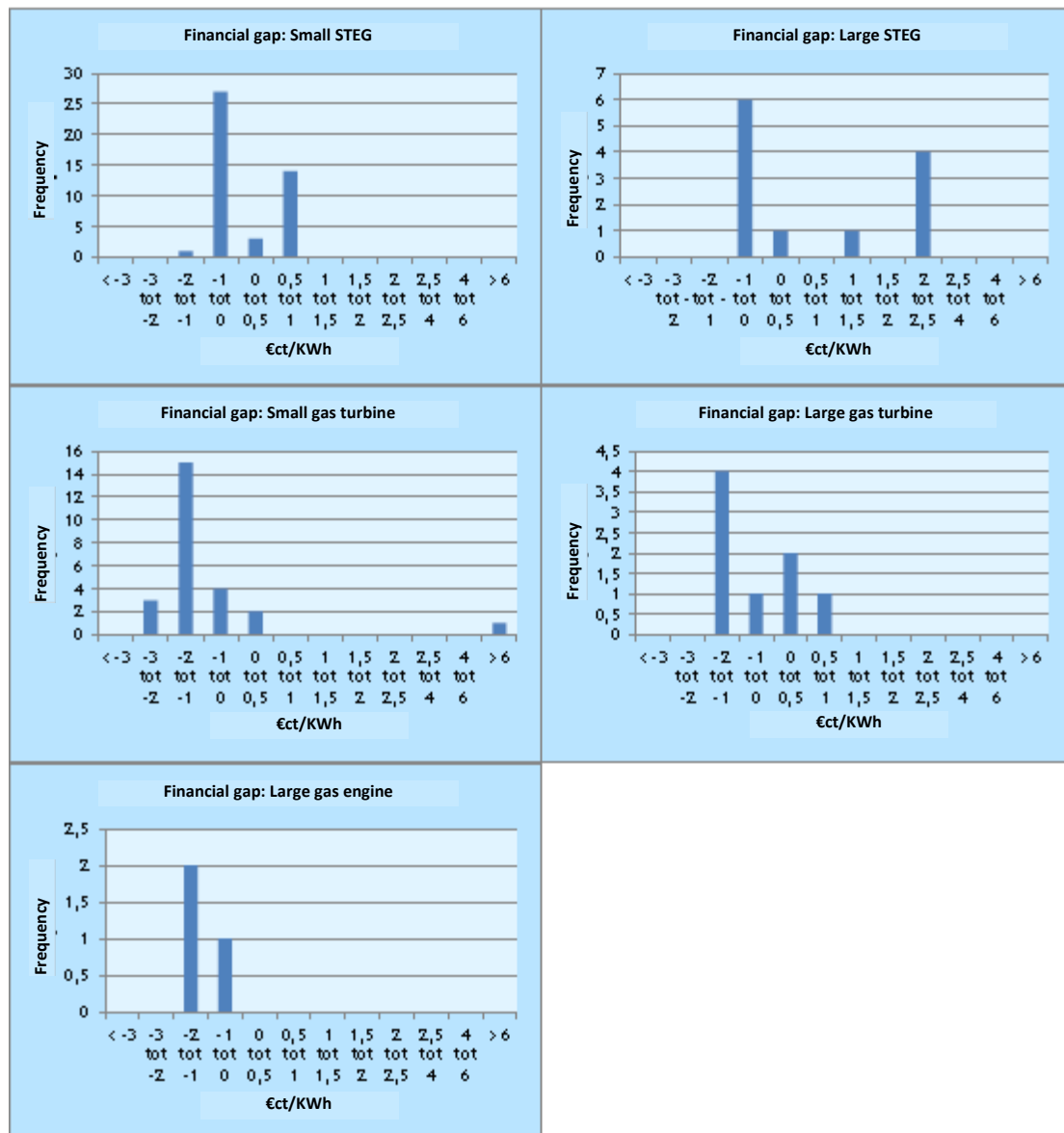
The graphs below show the financial gaps depending on the scale of the investment costs.



Key:
 inv. kosten = investment costs
 tot = to

J.5 2030 - Mark-up (€8.1/MWh)

The histograms for 2030 below are for the 25% case, those on the next page are for the sensitivity to 25% parameter.



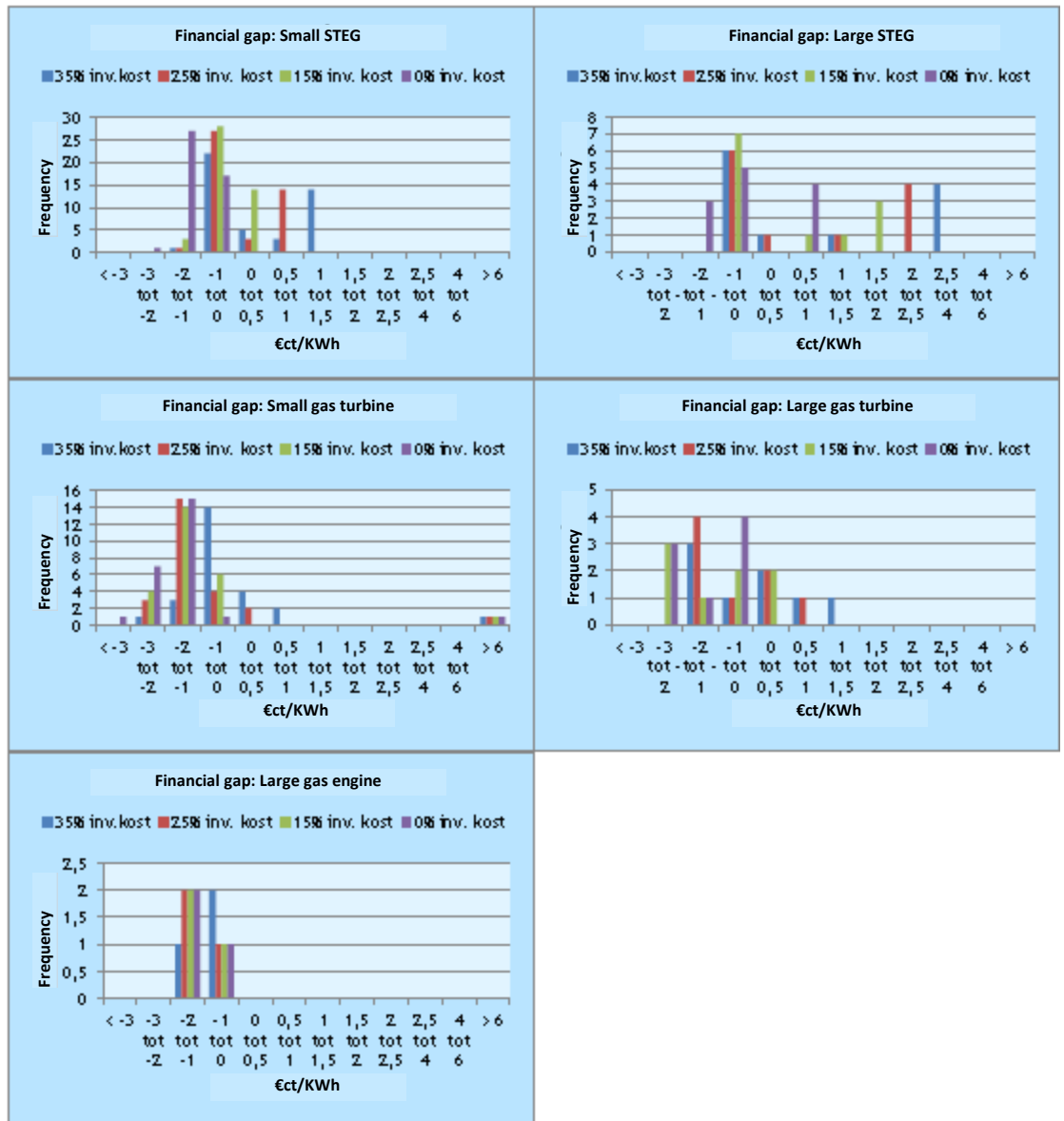
Key:
tot = to

The calculation takes account of:

- investments for retrofit costs to comply with NO_x requirements;
- new investment costs of 35% to 0% for all types.

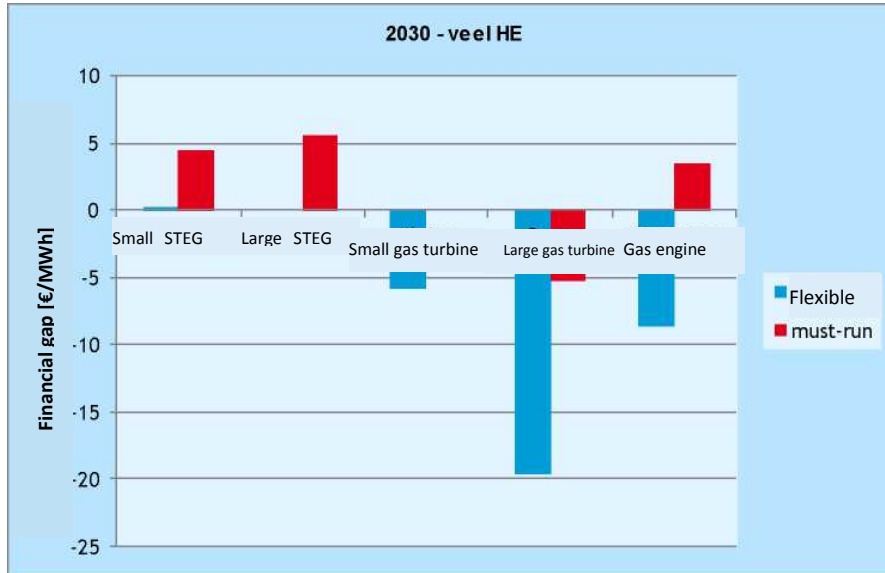
Including sensitivity to 25% new investment costs in the minimum retrofitting costs.

The graphs below show the financial gaps depending on the scale of the investment costs.

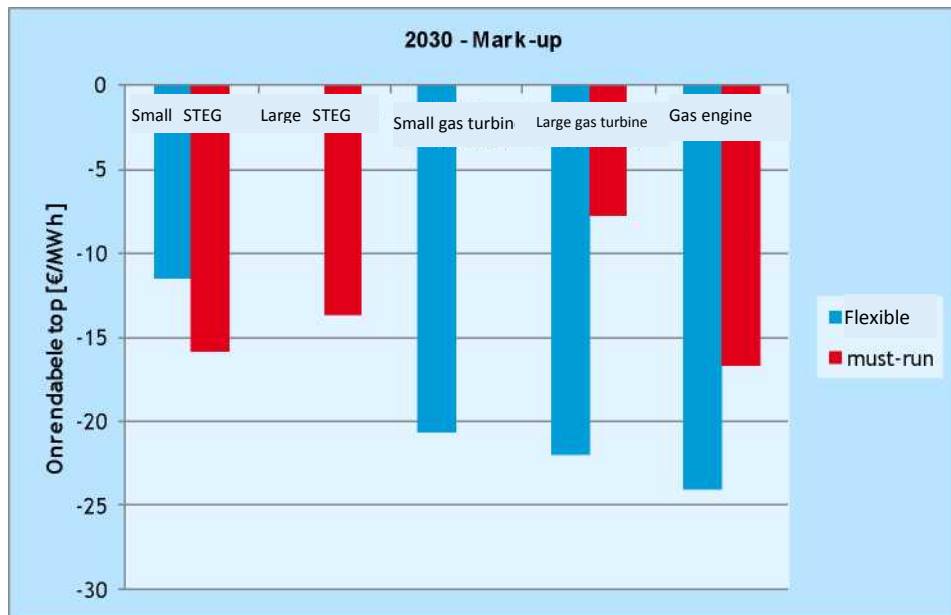


J.6 Position of must-run and flexible CHP installations in 2030 scenarios with a high share of renewable energy, mark-up and a high CO₂ price

The financial gap of flexible and must-run CHP installations in a scenario with a high share of renewable energy:



Financial gap of flexible and must-run CHP installations in a scenario with a mark-up.



Financial gap of flexible and must-run CHP installations in a scenario with a high CO₂ price.



Annex K Calculation of the impact of shutting down CHP capacity on primary energy use and CO₂ emissions

Primary energy use

The calculation is based on replacement of heat production by a boiler with an efficiency of 90%. Three scenarios are used for the substitute electricity production:

- replacement by new coal-fired power stations;
- replacement by new gas-fired power stations;
- replacement by fossil reference capacity, excl. CHP.

The change in primary energy use is the difference between the primary energy use of CHP installations and the total primary energy use of the substitute heat production and the substitute electricity production.

The electricity production assumes the following efficiencies and CO₂ emission factors, based on the DNV GL database:

	Generation efficiency, electricity		CO ₂ emission factor (kg/MWh)	
	2020	2030	2020	2030
New coal-fired power station	0.45	0.45	786	786
New gas-fired power station	0.58	0.60	348	336
Fossil reference capacity (excl. CHP)	0.45	0.51		

The reference capacity here is the fossil capacity, excluding CHP, as at 2014. It consists mainly of coal- and gas-fired power stations. The efficiency is the quotient of the electricity produced and the energy content of the fuel. This efficiency is relatively low, at 45%, because of the share of older gas- and coal-fired power stations. It is therefore the same as that of the new coal-fired power stations. The efficiency is higher in 2020, at 51%, because older coal- and gas-fired power stations will then have been shut down.

The efficiency is not corrected for transport losses, because CHP installations also have transport losses.

A boiler efficiency of 90% is assumed. The emission factor for gas is 56.1 kg CO₂/GJ.

The assumption that the reference facilities are fossil excl. CHP is in line with the Protocol for monitoring energy saving (ECN; RIVM; Novem; CPB, 2001) and the Memorandum on the calculation of reference efficiency (ECN, 2011).

The simulation calculation produces an electricity and heat production loss of:

		2020 base	2030 base	2020 base	2030 base
Original heat production CHP	[PJ]	91.6	104	91.6	104
Original electricity production CHP	[TWh]	30.2	34.7	30.2	34.7
Original emissions CHP	[Mtonne CO ₂]	14.8	16.9	14.8	16.9
Lost electricity generation CHP	[TWh]	15.8	19.2	24.3	28.2
Lost heat generation, CHP	[PJ]	40.3	48.8	70.2	80.7
Reduced CHP emissions	[ktonne CO ₂]	7.4	8.9	11.5	13.3

Result:

Calculation of impact on primary energy use	Proportion of phase-out 2020, revised calculation (52%)		Phase-out in 2020, revised incl. greenhouse horticulture (87%)	
	2020 base case	2030 base case	2020 base case	2030 base case
1. Primary energy use, CHP				
Gas used (PJp):	131	159	20 558	237
2. Primary energy use, substitute heat				
Lost heat production (Pje)	40.3	48.8	70.2	80.7
Primary energy use (PJp)	44.8	54.2	78.0	89.6
3. Primary energy use, substitute electricity				
Lost electricity production (PJe)	56.9	69.0	87.4	101.7
(PJe)				
A. replacement by gas	98.0	115	151	169
B. replacement by coal	126	153	194	226
C. replacement by ref. facilities (fossil, excl. CHP)	126	135	194	199
Growth in primary energy use	11.45	9.72	24.15	21.58
A. replacement by gas	39.76	48.06	67.70	78.06
B. replacement by coal	39.76	30.02	67.70	51.48
C. replacement by ref. facilities (fossil, excl. CHP)				

Calculation of the growth in CO₂ emissions:

	2020 <i>base case</i>	2030 <i>base case</i>	2020 <i>base case</i>	2030 <i>base case</i>
1. CO ₂ emissions from shut-down of CHP:	7.37	8.95	11.48	13.32
2. CO ₂ emissions from substitute heat	2.51	3.04	3.94	4.53
3. CO ₂ emissions from substitute electricity				
<i>A. replacement by gas</i>	5.50	6.44	8.45	9.49
<i>B. replacement by coal</i>	12.41	15.07	19.09	22.20
Growth of CO₂ emissions				
<i>A. replacement by gas</i>	0.64	0.53	0.91	0.69
<i>B. replacement by coal</i>	7.56	9.16	11.55	13.40

Annex L Suggestions from case studies

- Steam from residual waste:
 - simplification of licensing system for supply of third-party waste.
- Steam from biomass:
 - system of subsidies for biomass that takes account of future price fluctuations;
 - sufficiently broad criteria for sustainability of biomass;
 - focus on use of biomass for steam generation instead of electricity production;
 - (higher energy efficiency when used as heat source);
 - simplification of procedure for approval of waste as a fertiliser;
 - another option is supply of steam from supplementary biomass in coal-fired power stations.
- Geothermal energy:
 - fund for high-risk investments (e.g. revolving fund);
 - retention of guarantee scheme for geothermal wells;
 - no cap on amount of geothermal energy in SDE-Plus.
- Energy-saving/increase in efficiency of CHP:
 - risk-bearing government capital (off-balance financing) for investments in energy saving;
 - attention to CHP in policy.
- Making CHP flexible:
 - improve the possibilities for marketing CHP flexibility (balancing market TenneT, shorter periods of time);
 - support innovative forms of flexible CHP, such as power-to-heat and power-to-pressure.