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Potential analysis and cost-benefit analysis for cogeneration applications (transposition of the EU Energy Efficiency Directive) and review of the Cogeneration Act in 2014

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List of Abbreviations

ABL Alte Bundesländer [OFS old federal states]

AG Anschlussgrad [CR connection rate]

ALK Automatisierte Liegenschaftskarte [automated property map]

ALKIS Amtliches Liegenschaftskatasterinformationssystem

[official land survey information system] B

Betriebswirtschaftliche Betrachtungsweise [business

perspective]

BHKW Blockheizkraftwerk [BHPP block heat and power plant]

DMV Discounted Mean Value

EEG Erneuerbare Energien Gesetz

[Renewable Energies Act] EFH

Einfamilienhaus [OFH one-

family house]

EnEV Energieeinsparverordnung

[Energy Saving Regulations ETS

Emissions Trading System

GHD Gewerbe, Handel, Dienstleistungen

[CTS Commerce, Trade, Services GuDGas- und

Dampfturbine [G&S gas & steam turbine]

HA Hausanschluss [BC building connection]

HS Hochspannung [HV high voltage]

IFAM Fraunhofer-Institut für Fertigungstechnik und Angewandte Materialforschung

[Fraunhofer Institute for Manufacturing Technology and Advanced Materials IH

Instandhaltung [M maintenance]

IND Industrie [industry]

KWKG Kraft-Wärme-Kopplungsgesetz

[Cogeneration Act KWK Kraft-Wärme-

Kopplung [cogeneration]

KWKK Kraft-Wärme-Kälte-Kopplung

[Trigeneration] LoD1 Level of Detail 1

MFH Mehrfamilienhaus [AB apartment block]

MS Mittelspannung [MV medium voltage]

NBL Neue Bundesländer [NSF new federal states]

NS Niederspannung [LV low voltage]

NT Nachtstrom [OP off-peak electricity]

PHH Private Haushalte [private households]

REH Reihenendhaus [EOT end-of-terrace house

RMH Reihenmittelhaus (MOT mid-terrace house]

V Volkswirtschaftliche Betrachtungsweise [E economic perspective]

WP Wärmepumpe [HP heat pump]

1 Policy Brief

Status quo and short-term prospects

- Cogeneration plants currently generate approx. 96 TWh of electricity (net) and account for 16.2 % of total net power production in Germany. Just over half of that is accounted for by CHPP in the general supply network and just under one-third is accounted for by industry. The remaining cogenerated power is supplied by biogenic CHPP and small decentralised plants. Cogenerated heat (approx. 200 TWh) accounts for approx. 20 % of the heat market (<300°C).
- However, based on current market conditions, cogenerated power production will stagnate by 2020 compared to the current situation and the current target of 25 % cogenerated power by 2020 will therefore be well and truly missed.
- Even today, cogeneration saves approx. 56 million tonnes of CO_2 compared to uncoupled power and heat production. If additional cogeneration potential is tapped, it will be possible to increase the savings made compared to today, even though the future power generation system will be marked by further development of renewable energies.

Cost-benefit analysis and potential analysis

- It follows from the cost-benefit analysis that, from a business and economic perspective, cogeneration offers advantages over uncoupled systems in certain applications.
- For that reason alone, huge potential for further development of cogeneration has been identified, primarily in the general supply (district heating) and industrial sectors. Property CHPP offer additional potential in areas with no district heating connection. The overall potential for cogenerated power production, depending on the perspective chosen, is between 170 TWh/a and 240 TWh/a.
- The potential for district heating is highly sensitive. Even slight changes to basic conditions, i.e. including subsidy conditions, have a major impact on the results. A higher connection rate is essential; this depends on the necessary political flanking measures.
- For industry, power generation could rise by 50 % by 2030 to 43 TWh. The biggest potential for growth is in the foodstuffs, investment goods, consumer goods and commodities industries. Even by conservative estimates, the potential for power generation from waste heat is approx. 0.7 to 1.5 TWh a year.

Realisation, flexibility aspects and current market situation

- Cogeneration potential could be tapped in the medium-term at least (up to 2030) alongside continuing expansion of power generation from renewable energies. The fact that maximum input of fluctuating wind and PV power and the maximum heat requirement in district heating systems occur at different times has a positive impact here. After 2030, the facility to realise cogeneration potential depends on the structure of power generation, changes in the demand for power and the flexibility of the electricity system as a whole.

- Technically speaking, most CHPP are already able to react flexibly to signals from the electricity market. Most importantly, the flexibility of cogeneration could be further increased by building cheap heat storage facilities.
- Large CHPP (with capacity of several MW) have been supplying control energy for decades. This is also being achieved today by bundling smaller CHPP.
- Cogeneration in the general supply network is not economically viable for newbuild projects or plant modernisation projects under present conditions (low wholesale electricity prices). Of the present CHPP, only coal-fired CHPP can be operated economically at present and in the next few years. Natural gas-fired CHPP, on the other hand, cannot break even and operators are currently reporting losses and will continue to do so in future.
- For plants supplying properties and industry, economic viability depends enormously on the rate of private use of electricity and electricity purchase costs. Thus the achievable return on projects depends heavily on the specific situation in the properties/production sites to be supplied. The pro rata charge for private use of electricity in the form of the RES levy has depressed economic viability since the Renewable Energies Act Amending Act was passed.
- Energy-intensive undertakings often enjoy such considerable relief on electricity and energy tax and the RES levy and thus have such low energy purchase costs that there is hardly any profit to be made from new investments in large CHPP.
- Given the large number of residential buildings, there is huge potential for cogeneration in this sector. However, the high administrative cost of selling electricity directly and the repressive rules enacted under tax legislation often prevent this potential from being tapped, especially in light of the significant drop in wholesale electricity prices and thus the lack of incentive to deliver electricity to the grid.

Further changes to the Cogeneration Act

The current configuration of subsidies under the Cogeneration Act is to be maintained in its basic form. Subsidisation of cogenerated power production on the operating side not only improves the general economic viability of the subsidised plants; it also stimulates operation and thus results in primary energy and CO_2 savings compared to uncoupled generation.

Investment subsidies for the development of networks and storage facilities have proven their worth in

recent years. They should be retained.
Given current and anticipated market conditions over the next few years, subsidies for existing natural gas-fired CHPP in the general supply sector should be considered.
In order to facilitate newbuild and modernised CHPP in the general supply sector, surcharge rates should be increased considerably (by a factor of 2 to 3 compared to current levels, depending on the technology), especially for cogenerated power delivered to the grid.
By way of approximation, an additional 50 TWh of cogenerated electricity production would be needed in order to attain the cogeneration target by 2020. The existing cap in the Cogeneration Act needs to be raised considerably. Based on the simplified assumption that a cogeneration surcharge of 4-6 cents/kWh is needed, as a rough guide an additional EUR 2 billion to EUR 3 billion would be needed in subsidies in 2020. Other political action (capacity elements) or changes in the market situation might improve the economic situation of cogeneration projects and thus reduce the subsidy requirement.
The target system used to date to subsidise CHPP proves to be unsuitable in the long term, due to the increasing proportion of non-cogeneration-compatible power generation technologies (wind and PV). Converting targets to cogeneration-compatible power generation would appear to make sense in the long term, given the growing proportion of fluctuating power generation.
Individual points of the current rules governing cogeneration surcharges need to be adjusted. Proposals can be found in Chapter 7.7.
Aside from adjustments to the Cogeneration Act, emissions trading should be stepped up. The CO_2 price has lost its control function at present. Moreover, action should be taken to ensure equal treatment of heat supplied by CHPP in the ETS and heat supplied by decentralised heating systems which have no CO_2 costs.

2 Executive summary

2.1 Brief and approach

The EU Energy Efficiency Directive (2012/27/EU[1]) states that, by 31 December 2015, Member States shall carry out and notify to the Commission a comprehensive assessment of the potential for the application of high-efficiency cogeneration and efficient district heating and cooling. Article 14(3) states that the Member States shall carry out a cost-benefit analysis covering their territory. Furthermore, Section 12 of the current Cogeneration Act requires the act to be reviewed in 2014.

In light of that, the Ministry for Economic Affairs and Energy has decided to bring the potential and cost-benefit analysis forward to 2014 in order to draw conclusions as to the potential role of cogeneration in the future power and heat supply system and combine them with the review of the Cogeneration Act required by law.

The purpose of this project is to prepare a comprehensive study as the basis for decisions by the federal government. The study comprises the following modules, which build on each other in terms of content:

- cost-benefit analysis;
- cogeneration potential analysis;
- potential role of cogeneration in the future power and heat supply system and
- interim review of the Cogeneration Act.

The status quo identified in the study is based on current data and statistics. The consistent set of assumptions used in the current energy reference prognosis prepared by Prognos AG [Prognos/EWI/GWS 2014] was used to identify future changes in basic demographic, economic and energy parameters.

Cost-benefit analysis

The purpose of the cost-benefit analysis is to compare supply options and determine the most cost-effective options. The analysis was carried out by considering net present values and from both an economic and a business perspective. Basically, a distinction was made between applications in private households, applications in CTS and industrial applications.

The cost-benefit analysis does not relate directly to numerical data, unlike the subsequent potential analysis, which addresses the impact of the (current) economic viability comparisons.

Potential analysis

The potential analysis is based on the results of the cost-benefit analysis and illustrates the potential changes in quantities that may result for Germany as a whole.

The potential of grid-bound cogeneration in the **private household and CTS** sectors is based on a detailed analysis of 41 representative model towns. The heat requirement was extrapolated with due account for the effects of renovations and newbuilds. The potential of property cogeneration is based on a full cost comparison with a gas boiler for eight typical applications. The potential for **industry** has been determined from an analysis of the heat requirement of individual branches of industry in the temperature range of interest to cogeneration (<300°C) and future changes depending on changes in production and structural and technical effects.

Potential role of cogeneration in the future power and heat supply system

The analysis focuses on the potential for cogenerated power production, as that can be extrapolated in the potential analysis from the heat requirement covered by cogeneration. We investigated what technical concepts exist or are already being implemented to make cogeneration more flexible and the applications in which the flexibility of cogeneration is already being used.

We analysed the extent to which it will be possible to integrate cogeneration potential into the future power system and the role that cogeneration can play in the future power system, including in providing system security and security of supply. We determined the degree to which cogeneration will also have a long-term positive impact on CO_2 emissions.

Interim review of Cogeneration Act

The interim review considers the development of cogeneration and the take-up of cogeneration subsidies in recent years, as they give an indication of the impact of the Cogeneration Act. It has been used as a basis for short-term prospects (up to 2020), which will determine the future of cogeneration.

We therefore investigated the ratio between power production in CHPP and overall power production in Germany and changes to the inventory of CHPP subsidised under the Cogeneration Act and to networks and storage facilities. Another vital aspect of the review is how the economic viability of CHPP has changed. That has been determined by class of plant and type of use, taking account of revenue from power and heat production and, where applicable, subsidies under the Cogeneration Act. Based on that analysis, we estimated the changes in the proportion of cogeneration and the costs of the Cogeneration Act levy up to 2020.

We then formulated recommendations, based on our analysis, for changes to the Cogeneration Act for individual applications and for measures outside the scope of the act.

2.2 Cost-benefit analysis

Private households and CTS

The cost-benefit analysis of CHPP for **supplies to properties** makes a comparison between a gas-fired boiler and a smaller gas-fired boiler following thermal insulation of the building. Heat pumps are only suitable for low-temperature heating systems, i.e. they are a relevant alternative in newbuilds.

The net present values of the heating costs (in real terms) were calculated over a period of 30 years for the options investigated and then compared. In the residential sector, four single-family houses and eight apartment blocks were considered; in the CTS sector, the applications *hospital*, *office building* and *commercial business* were considered.

Considering one-family houses from an economic perspective, the use of a BHPP is by far the least economically viable option, due to the very high specific investments required in that sector. The net present values for the thermal insulation option are more or less identical to those of a gas-fired boiler, although the results here clearly depend on the renovation standard chosen. From a business perspective, capital expenditure-heavy thermal insulation is worse at BHPP level; a gas-fired boiler is then clearly the most economical option. The results were basically the same for apartment blocks.

In the CTS examples, a CHPP is slightly better from an economic perspective and far superior from a business perspective than a gas-fired boiler for the *hospital* application alone. From a business perspective, a BHPP is also slightly more economic than a gas boiler for the *commercial business* application. For the office building example, a gas-fired boiler is the option with the lower net present value from both an economic and a business perspective. The heat requirement of the property is always of vital importance; according to the cost-benefit analysis, the greater the requirement, the more advantageous the cogeneration option is over a gas-fired boiler.

For residential newbuilds, heat pumps fall between gas-fired boilers (cheapest supply option) and BHPP (most expensive supply option).

For **heat grid-bound CHPP**, there are so many different types of residential areas and imputable heat distribution costs that it is nigh impossible to establish a generally applicable benchmark.
The range of supply cases is therefore considered in the potential analysis.

Cost-benefit analysis of industrial cogeneration, trigeneration and ORC plants

The economic viability calculations for the six types of industrial CHPP considered here by way of example illustrate the importance of current cogeneration subsidies to the rate of return from a business perspective. This is especially clear for the smallest type of plant considered (BHPP with 50 kW_{el}.

With higher capacity, the rate of return in private generation in a CHPP is often undermined from a business perspective by the low electricity purchase costs which must be assumed for the larger, energy-intensive undertakings that operate such plants or would invest in such plants.
This applies in particular to large, power-intensive undertakings that enjoy relief on electricity tax (tax capping) and extensive relief on the RES levy. This is especially clear in two cases considered (steam turbine with 5 MW_{el} and G&S power plant with 20 MW_{el}), both of which are plants which require large investments, resulting in relatively high capital expenditure.

Taxes and duty are disregarded from the economic perspective. As a result, industrial CHPP tended to have even lower rates of return than from a business perspective.

The rate of return of a CHPP which also produces refrigeration using absorption technology depends enormously on the annual hours' use of the plant as a whole. Trigeneration plants could gain a stronger foothold more cheaply in certain branches which currently account for a small proportion of cogeneration in the heat requirement <300°C (e.g. food industry, other chemical industry).

There are at present only a few ORC plants in industry which generate power from waste heat. If the existing potential for development is tapped, however, perfectly profitable applications would be possible in future, especially for hotter waste heat.

2.3 Potential analysis

Private households and CTS

The **potential of grid-bound cogeneration** was determined based on the methodology of detailed analysis of representative model towns and transfer of their results to comparable towns. All 4 598 towns and associations of municipalities in Germany were subdivided into 9 sufficiently homogenous town categories based on structural data. In total they represent a useful heat requirement of 762 TWh/a.

We used 41 model towns from six federal states. A GIS-based, high-resolution digital heat atlas was prepared for all the towns containing a great deal of detailed information, including on building masses and surface area, building age class and type of use. Overall, the database contains more than 1.1 million buildings. The heat requirement values stored are based on typologies formed from around a quarter of a million real consumption data items. The IFAM used an in-house procedure, the accuracy of which was successfully validated using existing networks, to calculate building connection and distribution network lengths. The heat requirement was extrapolated with due account for the effects of renovations and newbuilds, differentiated spatially by associations of municipalities.

All model towns are clustered in spatial units based on their settlement structure. Each area is classed by whether it is an ‘island cluster’ (CHPP serves the heat demand of the cluster exactly) or part of a cluster network (positioning and sizing of CHPP is a monovariant). There is a total of 1 403 clusters.

The economic viability calculations are always carried out *on the heat side*; the results are reported as specific values (DMV, real values $€_{2013}$, net of VAT). They are performed for each cluster in accordance with the following condition (all figures in €/MWh):

Competitive district heating price
- Heat production costs
- <u>Heat distribution costs</u>

= x €/MWh

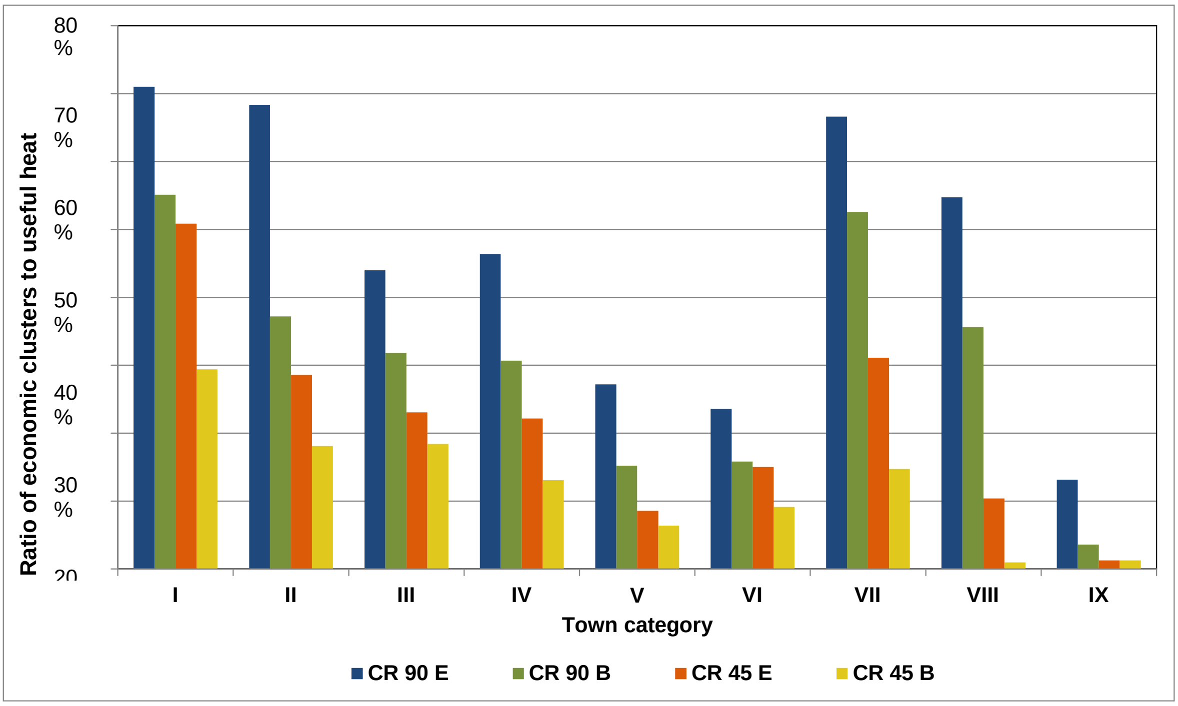
A cogeneration solution is economically viable where x > 0. In order to illustrate the sensitivity of the results, they are reported in graduated ‘economic viability increments’.

The competitive district heating prices obtained from full cost comparisons with gas-fired boilers for a mean mix of various sized buildings are 89.5 €/MWh from a business perspective and 79.4 €/MWh from an economic perspective.

From a business perspective, larger BHPP and smaller G&S plants offer the lowest heat production costs; a mix of equally represented plants gives production costs of 58 €/MWh. From an economic perspective, the production costs of larger G&S plants are slightly lower. With a mix of plants as before, the production costs are much lower (44 €/MWh).

Two scenarios are considered in each case, one to determine the maximum economic potential of a cogeneration supply with blanket coverage of the clusters with a connection rate (CR) of 90 % and one more realistic development scenario with the connection rate reduced by half to 45 %. Figure 1 summarises the scenario results. It illustrates the heat requirement ratio in the economic clusters for the reference case (x > 0), i.e. the ratios *before* the connection rate is considered, for the purpose of better comparison.

Figure 1: Results of cluster analyses for district heating cogeneration



CR: Connection rate in %, E: Economic perspective, B: Business perspective, for definition of town categories see *Table 14*

Source: IFAM 2014

The results substantiate the anticipated graduation between the town categories. There is clearly greater potential from an economic perspective, as the improvement to production costs clearly outweighs the deterioration in competitive heat prices, plus distribution costs are lower. With a reduced connection rate of 45 %, the heat quantity ratios of economic clusters fall considerably, on average by a good 50 %. Based on the reduced connection rate, the actual quantities of heat connected fall to around one-quarter. The potential is highly sensitive; slight changes to basic parameters clearly change the results.

Extrapolating the cogeneration potential to Germany gives the values in Table 1 for nationwide connections. Around half the potential is accounted for by towns in the old federal states with over 150 000 inhabitants.

Table 1: District heating cogeneration potential in Germany with connection rate of 90 %

Perspective	District heating cogeneration potential	Unit	Value
business	Heat demand	TWh/a	154
	Cogenerated heat production		128
	Cogenerated power production		113
economic	Heat demand		249
	Cogenerated heat production		207
	Cogenerated power production		182

Source: IFAM 2014

The calculations to determine the **potential of property cogeneration** are based on the results of the model cost-benefit analysis and a full cost comparison with a gas-fired boiler. A typical plant design is used for eight types of building and the minimum quantities of heat needed for an economically viable CHPP are determined.

Given that, as a rule, connection to a heat grid-bound system is the most economically viable option, only the buildings in the model towns outside economic district heat cogeneration clusters are considered in each scenario, in order to avoid counting them twice in the district heat cogeneration potential.

Each building is classed in one of 8 categories and checked individually against the economic viability criterion. In the scenarios with a connection rate of 90 %, the ratio of quantities of heat available for economically viable property cogeneration to the overall heat requirement of a town is obtained in the middle of the town categories:

- 4.5 % in the business calculation;
- 0.8 % in the economic calculation.

The percentages from an economic perspective are much lower for two reasons: the ‘success rate’ of the partial quantities investigated is much lower and the (cluster) quantities available are considerably smaller. The potential is limited to non-residential buildings. The rate of private use of electricity is of vital importance. The higher that rate, the more economically competitive the CHPP. The results of the extrapolation to Germany are illustrated in Table 2.

Table 2: Property cogeneration potential in Germany in CR 90 scenarios

Perspective	District heating cogeneration potential	Unit	Value
business	Heat demand	TWh/a	33
	Cogenerated heat production		21
	Cogenerated power production		14
economic	Heat demand		5
	Cogenerated heat production		3
	Cogenerated power production		3

Source: IFAM 2014

The two sub-potentials (district heating and property cogeneration) are added together to give the overall potential in the private household and CTS sectors. The results for the CR 90 scenarios are summarised in Table 3. It should be noted for the percentages given that the district heating cogeneration potential includes other properties which can also be economically represented as decentralised cogeneration solutions.

Table 3: Cogeneration potential in Germany in CR 90 scenarios

Generation potential	business	Percentage	economic	Percentage
	TWh/a	**%**	**TWh/a**	**%**
Cogenerated heat District heating cogeneration	128	86	207	99
Cogenerated heat Property cogeneration	21	14	3	1
Total cogenerated heat	**149**		**210**	
Cogenerated power District heat cogeneration	113	89	182	98
Cogenerated power Property cogeneration	14	11	3	2
Total cogenerated power	**127**		**185**	

Source: IFAM 2014

Potential of industrial cogeneration

Two different variations were calculated for future developments of power and heat production in CHPP in the processing industry for the period from 2012 to 2050 (baseline scenario, see Table 4, and a policy variation, see Table 39 in Chapter 5.2.8). They suggest:

- stagnation in the use of cogeneration in three industrial sectors (raw chemicals, stone/soil quarrying/other forms of mining and paper, peaking in part around 2020 to 2030) and
- a notable increase in the use of cogeneration in other sectors of

the processing industry (food, investment goods, consumer goods and commodities).

In the group of industrial sectors with stagnating cogeneration, the heat production potential in the baseline scenario with unchanged cogeneration subsidies initially rises up to 2030 by a good 11 % (+0.6 % per annum) and then falls up to 2050 by approx. 8 % compared to the potential in 2030 (see Table 4). Overall, that gives a slight increase in cogeneration potential of 1.3 TWh heat (approx. 2 %) and 0.9 TWh electricity up to the end of the period considered.

By contrast, the sectors with rising cogeneration potential, taken overall, show an increase of 13 TWh heat (5.7 % per annum) up to 2030 or a good 20 TWh (3.6 % per annum) up to 2050 (see Table 4). Overall, this development results in 2050 in heat that could potentially be produced by CHPP of approx. 91 TWh (+20 % compared to 2012) in the baseline scenario.

It should be noted that, in the base year (2012), on the heat side 82 % of cogenerated heat and, on the power side, just 88 % of cogenerated power can clearly be allocated to the aforementioned industrial sectors. Thus there is a gap of 18 % or 12 % compared to the official statistics which the authors are unable to allocate to corresponding sectors due to confidentiality criteria. Development of the potential for cogeneration which cannot be allocated is then projected to 2050 based on real data for 2012 and average growth rates of industry as a whole (see Table 4), in order to obtain a complete overall impression.

Table 4: Potential for heat and power production by CHPP in the processing industry in Germany 2012-2050, baseline scenario

Industrial sectors		Cogeneration potential, in GWh/a					Annual growth rate	
		2012	2020	2030	2040	2050	2012 - 2030	2012 - 2050
Heat	Industrial sectors with stagnating cogeneration1)	51 738	57 200	57 600	56 100	53 000	0.6 %	0.1 %
	Industrial sectors with increasing cogeneration2)	17 452	25 200	30 330	35 040	38 050	3.1 %	2.1 %
	Industry overall3)	**69 190**	**82 400**	**87 930**	**91 140**	**91 050**	**1.3 %**	**0.7 %**
	Unreported differences compared to statistics4)	14 935	16 614	18 980	19 673	19 653		
	Total potential of industry5)	**84 125**	**99 014**	**106 910**	**110 813**	**110 703**		
Electricity	Industrial sectors with stagnating cogeneration1)	19 690	23 450	23 830	22 730	20 520	1.1 %	0.1 %
	Industrial sectors with increasing cogeneration2)	5 158	10 550	14 100	17 450	19 470	5.7 %	3.6 %
	Industry overall3)	**24 848**	**34 000**	**37 930**	**40 180**	**39 990**	**2.4 %**	**1.3 %**
	Unreported differences compared to statistics4)	3 432	4 142	5 239	5 550	5 523		
	Total potential of industry5)	**28 280**	**38 142**	**43 169**	**45 730**	**45 513**		

1) Raw chemicals, stone/soil quarrying/other forms of mining and paper

2) Food and tobacco, automobile manufacture, glass and ceramics, rubber and plastic goods, machine engineering, metalworking, metal production, NF metals and foundries, other chemical industry, other branches of the economy and processing of stone and soil.

3) Total for industrial sectors considered in detail, excluding unreported differences compared to statistics

4) Difference is due to official statistics subject to confidentiality requirements.

5) Total for industry as a whole with unreported differences compared to statistics

Source: DESTATIS 2013 and 2014 a, b; VIK 2014, in-house calculations IREES 2014

The growth in CHPP in industry clearly slows down between 2030 and 2040. After 2040, the inventory stagnates due to negative growth of CHPP in branches which currently have a high proportion of CHPP; this is compensated by a further increase in plants in branches with greater potential for growth.

2.4 Potential role of cogeneration in the future power and heat supply system

The growing proportion of fluctuating renewable energies in the power system results in a different set of requirements, to which CHPP will also have to adapt in the long term. The objective of the first stage of the analysis was to describe that set of requirements in greater detail.

In the second stage, the technical concepts of CHPP were evaluated in terms of their flexibility and frequency in practical application. An analysis of the technical flexibility of CHPP already used today, compared to typical situations that have historically occurred on the electricity market, illustrates the role of cogeneration on the current electricity market.

The future role of cogeneration in the overall system is classified in conjunction with the consideration of cogeneration on the heat market. This was done by classifying it first in comparison to cogeneration-compatible power generation in the scenarios used for the energy reference prognosis, taking account of the potential analysis for the heat market.

The potential for cogeneration with higher ratios of renewable energy sources was also simulated in an hourly scenario without regulation of fluctuating renewable energies. This enabled the power-side limitation on cogeneration to be estimated in the long term. Finally, that analysis was used to calculate the CO_2 savings made from cogeneration of heat and power in future energy systems.

The following core results were obtained from the individual stages of the analysis:

Requirements of the electricity system of the future

The growing proportion of fluctuating renewable energies on the electricity market presents the electricity system with three core challenges: Aside from preventing economically inefficient systematic electricity surpluses and refinancing of capacity backup on the electricity market, supply system services represent a core challenge. They give rise to the flexibility requirements on cogenerated power production which are needed for its efficient integration in the energy system of the future.

Technical concepts for more flexible CHPP

Cogenerated power production, as part of what tend to be large heat supply systems in industry and in the general supply network using plant concepts, heat storage facilities and peak load boilers, offers enough technical flexibility to be able to survive in the long term, even in a system with high proportions of fluctuating renewable energies. The applications in property supply have the same technical flexibility options.

Current use of flexibility of CHPP to prevent down-regulation of RES plants

There does not appear at present to be any systematic inflexibility caused by cogeneration technology in the electricity system.
On the contrary, the generation profile of cogeneration in the general supply network in particular corresponds very well with input of renewable energies. There is therefore no cause to assume that the technical potential to make CHPP more flexibility in future has been exhausted. The fact that the technical potential for flexible operation of CHPP is not yet being fully exploited is due almost solely to the fact that they are not yet economically attractive. In particular, in the case of non-privileged end users and compared to plants marketed on the electricity market, private generation concepts react only in the case of very marked electricity price signals. However, these plants still account for a small proportion of the inventory. We estimate that this accounts for one-third of industrial cogenerated power production (10 TWh) and the lion’s share of power production by plants under 1 MW (5 TWh).

Cogeneration on the heat market

On the heat market, approx. 15 % is currently produced by CHPP. In the long-term and especially in densely populated areas, cogeneration offers a cheap and resource-efficient option for a low CO_2 heat supply. In the long term, however, the proportion of district heating supplied from RES should be increased in order to exhaust the potential on the heat side. In that context, power-to-heat concepts may also favour the integration of a higher proportion of fluctuating RES in the electricity market.

Long-term role of cogeneration in the overall system

From an historical perspective, the use of cogeneration technology has been restricted mainly by inadequate use of existing heat sinks. This restriction on the heat side will be compounded in the long term in future by increasing proportions of fluctuating renewable energy sources on the power side. With technical flexibility, CHPP will also make an economically sensible contribution to a cost- and resource-efficient supply of power and heat in the long term. By making use of additional flexibility options in the electricity system, such as cross-border electricity trading or the use of power-to-heat applications, it

will be possible to develop the as yet untapped potential of cogeneration technology. The target system used to date to subsidise CHPP is proving to be unsuitable in the long term, due to the shifts in the electricity system.
Converting targets to cogeneration-compatible power generation would appear to make sense, given the growing proportion of fluctuating power generation.

CO_2 savings from cogeneration

Furthermore, cogeneration continues to make a clear contribution to CO_2 savings. Even if now only gas-powered plants are crowded out of the electricity mix on the German electricity market in the long term, there is still be a considerable advantage over uncoupled production in the CO_2 balance.

2.5 Review of Cogeneration Act

The Cogeneration Act provides for an interim review in 2014. The objective is to investigate the degree of attainment of the energy and climate policy objectives of the Federal Government, the basic conditions for the operation of CHPP and the annual surcharge payments.

The following chapter describes the development of cogenerated power production over the past ten years (Chapter 7.1) and evaluates the CHPP, heat and cooling storage facilities and heating and cooling networks subsidised under the Cogeneration Act since 2003 or 2009 (Chapter 7.2 to 7.4). That information and the economic viability calculations performed (Chapter 7.5) are used as the basis for a prognosis of cogenerated power production and the costs of the Cogeneration Act levy up to 2020 (Chapter 7.6). This is followed by recommendations for the further changes to the Cogeneration Act (Chapter0).

Ratio of cogeneration to overall power production in Germany

In 2013, with net electricity production of 96.4 TWh (2003: 82.4 TWh), cogeneration accounted for approx. 16.2 % (2003: 14.2 %) of net electricity production in Germany. Cogenerated power production in the general supply sector has stagnated or fallen slightly in the past decade. On the other hand, industrial cogenerated power production, CHPP under 1 MW and biogenic cogeneration are increasing and driving the overall slight growth in cogeneration. CO_2 savings from combined production in CHPP, compared to uncoupled reference production, were approx. 56 million tonnes in 2013.

CHPP subsidised under the Cogeneration Act

The Cogeneration Act currently recognises three different subsidisation criteria for CHPP. They are newbuild, modernisation and retrofitting of CHPP.

The 2009 Cogeneration Act Amending Act increased subsidised additions and modernisation together to a level of over 500 MW per annum. Following the amendments to the Cogeneration Act in 2012, that value rose in 2013 to just 1 100 MW, due mainly to the increasing volume of modernisations of plants of over 2 MW.

Modernisation of plants of over 2 MW electricity capacity accounts for 42 % of all cogenerated capacity subsidised since 2012. Newbuilds in this segment account for 27 % of the cogenerated capacity subsidised. In the sector below
2 MW, modernisation plays only a minor role. Newbuild plants between 50 kW and 2 MW account for approx. 23 % of the cogenerated capacity subsidised and the segment below 50 kW accounts for approx. 6 %. With just one subsidy case, retrofitting is immaterial.

Property and industrial cogeneration have grown dynamically in recent years, with the 50 kW to 2 MW capacity segment recording the highest growth rate. The increase in the cogeneration surcharge under the 2012 Cogeneration Act Amending Act and the sharp increase in the RES levy between 201, which may private use of the electricity generated more economically attractive, were probably responsible for that growth.

Heating and cooling networks subsidised under the Cogeneration Act

Expansion of heating networks is an important basic pillar in maintaining and expanding cogeneration, as it increases heat sales or stabilises them in cases of successful thermal insulation of buildings and processes and the efficient application of heat. As large solar heat plants, geothermal plants and power-to-heat technologies are integrated in future, heating networks will help to boost the use of biomass and further decarbonise the cogeneration system.

Construction of heating and cooling networks has been subsidised under the Cogeneration Act since 2009. Under the 2012 Cogeneration Act Amending Act, the maximum possible investment subsidy of 20 % was
30 % or 40 % for networks with a nominal diameter of less than 100 mm. Heating networks are subsidised in which at least 60 % of the heat delivered is cogenerated.

Between 2009 and 2011,
an average of 400 km of lines were commissioned. Following the amendments to the Cogeneration Act in 2012, that value jumped to a good
800 km of lines per annum. Newbuilds, extensions, network mergers and network development are subsidised; most important are extensions, which account for 54 % of line kilometres, and newbuilds, which account for 40 %. While newbuild projects rely

more on renewable energy sources, extension projects tend to use fossil fuels. To date only heating networks have been subsidised.

Heat and cooling storage facilities subsidised under the Cogeneration Act

Plant engineering which connects thermal storage facilities and electricity market-driven CHPP can contribute enormously to more flexible power generation by CHPP. It allows cogenerated power production to be uncoupled at times from heating and cooling requirements.

The 2012 Cogeneration Act Amending Act introduced subsidies for heat and cooling storage facilities in the form of an investment subsidy under the Cogeneration Act of a maximum of 30 % of the eligible investment costs, capped at EUR 5 million per project. Since that subsidy was introduced, 89 storage projects with a total storage capacity of approx. 8 100 m^3 have been completed. A further 81 heat storage facilities with a capacity of approx. 53 000 m^3 are still in the approval procedure. Plans to build numerous additional storage facilities with capacity of approx. 230 000 m^3 have also been announced. To date only heat storage facilities have been subsidised.

The overall capacity of just under 300 000 m^3 of the storage facilities already implemented or due to be implemented already covers approx. 7 % of the storage capacity required up to 2050 (estimated at 4 million m^3 [Prognos 2013]).

Economic viability of CHPP

The only public district heating supply plants which can break even in the short term (up to 2020) under the basic conditions described are modern coal-fired CHPP. Without subsidies, gas-fired CHPP are not economically viable in any of the cases considered. Only plants with a high electrical efficiency rating in some years can achieve a positive contribution margin. As of 2017, as gas and electricity prices converge further, it will no longer be possible for any plants to achieve that. At present newbuild public CHPP for district heating with cogenerated electricity capacity of over 10 MW cannot be refinanced.

Larger property and industrial CHPP, on the other hand, can be erected and operated in suitable applications under present subsidy law. Numerous applications achieve a sufficiently high rate of return on the project without any cogeneration subsidy. The highest rates of return on projects are achieved where plants attain high capacity utilisation and where a large proportion of the electricity can be used by the operator itself. This is usually the case in industrial sectors with a high and generally constant demand for power and heat.

Consumers in energy-intensive industries enjoy relief on levies and electricity is therefore cheap to buy; therefore, although a new

CHPP would be expected to generate a positive rate of return on the project, it would tend to be below the minimum rate of return for implementing the project. Adjusting subsidies could generate new momentum in this segment.

Smaller plants, especially in residential properties do not achieve a positive rate of return under current conditions. With a negative rate of return on projects, plants are only built here and there based on non-monetary criteria.
Although small to medium-sized plants for supplying properties may achieve a positive rate of return, it is often below the minimum rate of return and, as a rule, these projects are not implemented. Overall, plants in CTS and residential buildings are only economically viable in selected instances. For plants supplying properties, economic viability depends enormously on the rate of private use of electricity. Very good rates of return on projects can be achieved in certain applications, such as hotels or hospitals. In sectors such as the residential sector, however, projects are very hard to implement.

The reasons for this are, first, the higher specific costs of the smaller plants and, second, the low rate of private use of the electricity generated.

Cogenerated power production prognosis up to 2020

The prognosis is based on current cogenerated power production. It takes account of the main developments in cogeneration for general supply, industrial cogeneration and biogenic and small-scale cogeneration. The prognosis takes account of newbuild projects already announced and the results of the economic viability study, as well as the changes to private consumption made in the 2014 RES Act. The Cogeneration Act is extrapolated in its present form. It disregards potential effects of the introduction of a capacity market in the future.

Net cogenerated power production will remain more or less at current levels up to 2020. The development of cogeneration will differ from application to application. For CHPP for general supply, the economic situation will probably cause a decline in cogenerated power production, whereas a slight increase compared to current levels is anticipated for industrial cogenerated power production up to 2020. There is attractive potential in particular for undertakings and branches with high electricity purchase costs and high heat and power consumption.

3 Brief and approach

The EU Energy Efficiency Directive (2012/27/EU[2]) states that, by 31 December 2015, Member States shall carry out and notify to the Commission a comprehensive assessment of the potential for the application of high-efficiency cogeneration and efficient district heating and cooling. Article 14(3) states that the Member States shall carry out a cost-benefit analysis covering their territory which identifies the most resource-and cost-efficient solutions to meeting heating and cooling needs taking account of climate conditions, economic feasibility and technical suitability.

Furthermore, Section 12 of the current Cogeneration Act requires the act to be reviewed in 2014.

In light of that, the Ministry for Economic Affairs and Energy has decided to bring the potential and cost-benefit analysis forward to 2014 in order to draw conclusions as to the potential role of cogeneration in the future power and heat supply system and combine them with the review of the Cogeneration Act required by law.

The purpose of this project is to prepare a comprehensive study as the basis for decisions by the federal government. The study comprises the following modules, which build on each other in terms of content:

- cost-benefit analysis;
- cogeneration potential analysis;
- potential role of cogeneration in the future power and heat supply system and
- interim review of the Cogeneration Act.

This study uses uniform assumptions for all calculations. On the one hand, they include energy economy guidelines on future developments and the assumptions based thereon in terms of price trends for fuel and CO_2 certificates and the wholesale and retail prices extrapolated from those prices. On the other hand, the study takes a uniform typological approach to the technical parameters and costs of the CHPP investigated.

Cost-benefit analysis

The purpose of the cost-benefit analysis in Chapter 4 is to compare supply options and determine the most cost-effective options. The analysis was carried out from both by considering net present values and from an economic and a business perspective, which differ as follows:

- The **economic perspective** uses the entire economy of Germany as its reference framework. It disregards the impact of politically-driven frameworks (taxes, duty, subsidies). That analysis fulfils EU reporting requirements.

- The **business perspective** takes a view from the perspective of the decision-makers; the reference framework is the private supply area, undertaking or building. Unlike the economic perspective, that perspective reflects the entire current legal framework (e.g. tax legislation). It also takes account of fluctuating interest rates, which reflect the rate of return anticipated by individual stakeholders.

Due to the numerous potential applications for cogeneration, only a sample of CHPP in typical applications are considered. Basically, a distinction was made between applications in **private households**, applications in **CTS** and **industrial applications**.

The cost-benefit analysis does not relate directly to numerical data, unlike the subsequent potential analysis, which addresses the impact of the (current) economic viability comparisons.

Potential analysis

The potential analysis in Chapter 5 is based on the results of the cost-benefit analysis and illustrates the potential changes in quantities that may result for Germany as a whole. The cost functions determined in the cost-benefit analysis provide the main basis for estimating potential.

Work to determine the **potential of grid-bound cogeneration** in the private household and CTS sectors was based on the methodology of detailed analysis of 41 representative model towns and transfer of their results to comparable towns. The heat requirement was extrapolated with due account for the effects of renovations and newbuilds.

The potential of **property cogeneration** is based on a full cost comparison with a gas boiler for eight typical applications. Only the buildings in the model towns outside economic district heat cogeneration clusters are considered in each scenario, in order to avoid counting them twice in the district heat cogeneration potential.

The potential for **industry** has been determined from an analysis of the heat requirement of individual branches of industry in the temperature range of interest to cogeneration (<300°C) and future changes depending on changes in production and structural and technical effects. The cogenerated power produced was extrapolated from assumptions on the technology used (primarily BHPP and gas turbines) and their specific power and heat production conditions based on financial viability calculations.

Potential role of cogeneration in the future power and heat supply system

The potential role of cogeneration in the future power and heat supply system is analyses in Chapter 6 based on the results of the potential analysis and the cost-benefit analysis. The analysis focuses on cogenerated power production, as that can be extrapolated in the potential analysis from the heat requirement covered by cogeneration.

The starting points for the analysis of cogeneration are therefore, first, the power production potential determined and, second, the changing requirements of the power system as a whole. The progressive integration of increasing proportions of renewable energies means that a more flexible approach is needed for all load-following power plants. Moreover, there is a growing need for control energy and system services.

We therefore started by investigating what technical concepts exist or are already being implemented to make cogeneration more flexible and the applications in which the flexibility of cogeneration is already being used. Furthermore, using typical district heating and RES production profiles, we analysed on an hourly basis if their production maxima overlap and thus interfere with each other or occur at different times and thus complement each other.

Based on this, we analysed the extent to which it will be possible to integrate the cogeneration potential determined into the future power system and the role that cogeneration can play in the future power system, including in providing system security and security of supply. That analysis was based on findings from current studies.

One fundamental advantage of cogeneration today is that coupled power and heat production saves CO_2 compared to uncoupled systems. Future changes to the mix of energy sources used for power and heat production will affect the emission inventory of cogeneration and its reference systems. We therefore determined the degree to which cogeneration will also have a long-term positive impact on CO_2 emissions.

Interim review of Cogeneration Act

In Chapter 7, we establish the scientific basis for this review by the federal government based on the results of the potential analysis and cost-benefit analysis, taking account of the potential future role of cogeneration in Germany. For the interim review, the focus is more on the past and the immediate future. First, the development of cogeneration and the take-up of cogeneration subsidies over recent years are important, as they map the impact of the Cogeneration Act and, second, the short-term prospects up to 2020 are instrumental to the future of cogeneration. The following points in particular are analysed:

- ratio of power production in CHPP to overall power production in Germany;
- changes to the inventory of CHPP subsidised under

the Cogeneration Act and to networks and storage facilities;

- the economic viability of CHPP, determined by class of plant and type of use, taking account of revenue from power and heat production and, where applicable, subsidies under the Cogeneration Act;
- changes in the proportion of cogeneration and the costs of the Cogeneration Act levy up to 2020.

Based on that analysis, we have formulated recommendations for changes to the Cogeneration Act for individual applications and for measures outside the scope of the act.

4 Cost-benefit analysis

The cost-benefit analysis was carried out as it is required under the Energy Efficiency Directive. The purpose is to compare supply options and determine the most cost-effective options. The analysis was carried out from both an economic and a business perspective, by considering net present values.

Private households and CTS

The cost-benefit analysis of CHPP for **supplies to properties** makes a comparison between a gas-fired boiler and a smaller gas-fired boiler following thermal insulation of the building. Heat pumps are only a relevant alternative in newbuilds. In the residential sector, four single-family houses and eight apartment blocks were considered; in the CTS sector, three examples of applications were considered.

We found for cogeneration for property supply that economically viable use of a **BHPP** is not possible in the private household sector under the basic conditions assumed. This applies from both an economic and (to a lesser extent) business perspective. Due to the lower specific investment of costs of larger BHPP, larger apartment blocks perform better than smaller residential buildings. In the CTS sector, the economic viability of BHPP depends enormously on the specific building and the perspective taken; it is therefore not possible to make any generalisations as to the economic viability of CHPP.

For the examples chosen, **thermal insulation** has similar net present values as the gas-fired boiler option from an economic perspective. Based on the interest rates applied in the business variation, thermal insulation is not an economically viable alternative in the examples used. These results cannot be plausibilised, as the comparisons depend enormously on the state of the building, the measures used and assumptions such as our own interest rate forecasts.

The net present values of **heat pumps** are higher than the net present values of the gas-fired boiler option (slightly to markedly from an economic perspective and considerably from a business perspective).

For **heat grid-bound CHPP**, there are a great many different types of residential areas and imputable heat distribution costs; the cost-benefit analysis has therefore been carried out within the framework of the potential analysis.

Industrial cogeneration

The power production costs that can be achieved with industrial CHPP are a relevant parameter for investors and operators. It is therefore crucial to determine them in order to estimate the potential for cogeneration in industry. The heat generated is valued at the cost of heat produced separately.

The electricity production costs were calculated and compared to the electricity purchase costs that would otherwise apply to industrial investors/users for the six types of plant chosen as examples (three BHPP with varying electrical capacity between 50 kW_{el} and 2 MW_{el} and one steam turbine, one gas turbine and a G&S power plant with rated capacity of between 5 MW_{el} und 20 MW_{el}).

The results illustrate the importance of current cogeneration subsidies to the rate of return on plants, especially the smallest BHPP with 50 kW_{el}. With larger plants, the return on investment in private generation in a CHPP is often undermined by the low electricity prices which apply to large, energy-intensive undertakings. The benefits of the RES levy or of the relief/exemption on electricity and energy taxes can be felt here. The results of the cost and profitability calculations suggest that growth in industrial cogeneration in future should be driven primarily by BHPP and gas turbines of up to approx. 5 MW.

We complemented the profitability calculation from the point of view of an investor (business perspective) with an economic cost-benefit analysis. For that we used energy prices net of any taxes, duty and levies (RES and cogeneration levies). However, that economic perspective has the disadvantage that the prices do not take account of changes to the energy system pursued under energy and climate policies or the need to avoid high adaptation costs and damages.

The cost-benefit analysis was carried out as it is required under the Energy Efficiency Directive. The objective is to investigate the various cogeneration applications in terms of their overall costs and compare them with other supply options, in order to determine the most cost-efficient options. The analysis was carried out by considering net present values and from both an economic and a business perspective, which differ as follows:

- The **economic perspective** uses the entire economy of Germany as its reference framework. It disregards the impact of politically-driven frameworks (taxes, duty, subsidies). That analysis fulfils EU reporting requirements.
- The **business perspective** takes a view from the perspective of the decision-makers; the reference framework is the private supply area, undertaking or building. Unlike the economic perspective, that perspective reflects the entire current legal framework (e.g. tax legislation). It also takes account of fluctuating interest rates, which reflect the rate of return anticipated by individual stakeholders.

The cost components considered, which are calculated for each year and then input into the net capital value of overall heat production costs, are given in Table 5.

Table 5: Cost/expenditure components taken into account for economic and business cost-benefit analysis

Costs/expenditure	**Economic perspective**	**Business perspective**
Investment costs	Yes	Yes (with VAT in private household sector)
Operating costs	Yes	Yes (with VAT in private household sector)
Fuel costs	Excluding	Including all relevant taxes
Energy tax refund	N/A	Yes if P_{el} < 2 MW
CO_2 duty	No	Yes
Cost savings from private consumption	Yes	Yes
Revenue from sales of electricity	Yes	Yes
Network fees	Yes	Yes
RES levy	No	Yes
Cogeneration Act surcharge	No	Yes

Source: IFAM

The interest rates assumed for both the economic and the business perspective are listed in Table 6.

Table 6: Yield assumptions for cost-benefit analysis

Real interest rates (for complete investment)	**Economic perspective**	**Business perspective**

Private households	3 %	6 %
CTS	3 %	8 %
IND	3 %	12 %
Energy economy/district heating	3 %	8 %

Source: IFAM

Positive results from an economic perspective suggest that realising the potential determined would benefit the economy as a whole. The comparison between the business perspective and the economic perspective provides information on the need for an impact of possible political intervention to subsidise one option or another, i.e. to improve the basic conditions for the cogeneration and district heating investments to be made to the extent that the discrepancy is reduced or even eliminated.

Due to the numerous potential applications for cogeneration, only a sample of CHPP in typical applications are considered. The options investigated follow from the client's requirements and the relevant/dominant alternatives on the individual sub-markets. Basically, a distinction was made between applications in **private households**, applications in **CTS** and **industrial applications**.

The cost-benefit analysis does not relate directly to numerical data, unlike the subsequent potential analysis, which addresses the impact of the (current) economic viability comparisons. The cost functions determined in the cost-benefit analysis provide the main basis for estimating potential.

4.1 Common basic conditions

This study uses the **uniform assumptions** for all calculations, as presented below. On the one hand, they include energy economy guidelines on future developments and the assumptions based thereon in terms of price trends for fuel and CO_2 certificates and the wholesale and retail prices extrapolated from those prices. On the other hand, the study takes a uniform typological approach to the technical parameters and costs of the CHPP investigated.

The **Federal Government Energy Concept 2010**, which was supplemented in 2011 to take account of the withdrawal of the extension to the lifetime of nuclear power plants and measures to expand the grid and develop renewable energies, sets out the long-term strategy for converting the energy system to a more climate-neutral system. The objective of the energy concept, aside from developing renewable energies and improving energy efficiency, is therefore to increase the proportion of cogenerated power to 25 % by 2020. Current energy policy supports that objective. However, the increase in deliveries from fluctuating renewable energy sources (wind power and photovoltaics) represents a new challenge to the power system in general and thus cogeneration in particular. CHPP will have to be made more flexible in future, in order to better adapt the required development of cogeneration to the demands of the changing power system. However, this offers CHPP operators an opportunity to increase the income from their plants through more flexible operation of their plants and thus improve their rate of return.

The current **energy reference prognosis** [Prognos/EWI/GWS 2014] analyses probable changes in the energy economy up to 2030 from the current 's perspective, in light of the long-term background of the measures and strategies adopted in the energy concept, and extrapolates them in a trend scenario extending to 2050. Unlike the target scenario also described in [Prognos/EWI/GWS 2014], the reference prognosis takes account of existing inertia forces and delays in the implementation of climate protection-related measures.

The reference prognosis also contains consistent conclusions as to changes in energy prices on international markets and in Germany. Table 7 below illustrates the basic changes in **energy and CO_2-certificate prices** applied. Prices on the crude oil, natural gas and boiler coal markets are expected to rise, triggered by the increasing global demand for energy, especially in Asia. The prices in the table below are corrected for the effects of inflation, i.e. are given in real prices based on 2013. The price of oil rises in the scenario between 2014 and 2050 from USD 116/barrel (real) to over USD 130/barrel. The German cross-border price for crude oil rises over that period, taking account of the change in the exchange rate between the US dollar and the euro, from EUR 685/t to EUR 934/t. The cross-border price for natural gas and coal increase, from EUR 27/MWh to EUR 35/MWh for natural gas and from EUR 65/t per unit to EUR 143/t per unit for coal. The assumed changed in energy prices are a likely price scenario as things currently stand. One-off impacts , such as political or economic crises or extreme weather compared to long-term averages, may cause considerable fluctuation in the prices of individual energy sources, at least in the short term. The change in the price of CO_2 also depends enormously on political decisions. It is particularly difficult to estimate the price of CO_2 for the period post-2020.

Table 7: Energy prices based on energy reference prognosis

		2014	**2020**	**2030**	**2040**	**2050**
International oil price	USD2013/bbl	116	122	129	131	133
Crude oil cross-border price	EUR2013/t	685	730	818	874	934
Natural gas cross-border price (Ho)	EUR2013/MWh	2.7	3.1	3.2	3.5	3.5
Gas price CPT power plant (Ho)	EUR2013/MWh	31	35	36	38	38
Coal cross-border price	EUR2013/t per unit of coal	65	112	124	135	143
Coal price CPT power plant	EUR2013/MWh	9	14	16	17	18
CO_2 certificate price	EUR2013/t	5	10	42	68	80

Wholesale electricity price (baseload)	EUR_{2013}/MWh	36	42	67	83	87

Source: Prognos/EWI/GWS 2014

The fuel prices do not include any surcharge for CO_2 emissions. CO_2 certificate prices are shown separately. They persist at low levels up to 2020 and rise post-2020 to EUR 80/t in the assumed scenario up to 2050.

This study includes a detailed economic viability analysis for CHPP in all applications. Important parameters for large CHPP in the public supply sector are the revenue from sales of power and heat and the costs of fuel and CO_2 certificates. For CHPP in properties and industry, aside from the individual retail prices of electricity and natural gas, other factors such as annual hours' use, the temperature level of the heat consumer appliance or the facility for simultaneous production of absorption refrigeration are also relevant.

The natural gas retail prices listed in Table 67 in the annex (Section 9.1.1) are based on the current price structure in the consumer classes identified by Eurostat. Future changes in those retail prices will be closely linked to changes in the cross-border price in the energy reference prognosis (see Table 7) and surcharges for the structuring, transportation and margins of gas distribution. These components all depend on consumer group and consumer categories. Retail prices post-2020 are enhanced by the costs of the CO_2 emissions in Table 7.

Future real gas prices for various end customers net of value added tax, taxes and duty are given in the annex (Section 9.1.1). The prices are of relevance as fuel prices in the economic viability calculations for property and industrial cogeneration on two counts: first, as the fuel price for the CHPP itself and, second, as an input parameter to calculate revenue from heat by determining the heat production costs of an alternative boiler.

Even the retail prices of electricity differ depending on customer group and consumption category. That is due, first, to different consumption quantities and, second, to the varying levies, taxes and fees under current legislation. A detailed breakdown of electricity prices for the consumption categories considered can be found in the annex (Section 9.1.1) in Table 64 to Table 66.

The real retail prices for electricity up to 2050, assuming the law stays the same, can be found in the annex (Section9.1.1). These prices are based on the changes to wholesale electricity prices in Table 7 and assumptions as to future changes in duty and levies. Value added tax is only paid by private households and the public sector (e.g. hospitals, schools).

In industry in particular, the energy prices applicable to individual undertakings may differ from the typical average prices presented here.

The 2012 Cogeneration Act surcharge rates used in the calculations can be found in Table 8.

Table 8: 2012 Cogeneration Act surcharge rates

Plants entitled to a surcharge	**By capacity**	**Cogeneration surcharge***	**Payment period**
Small CHPP up to and including 50 kW$_{el}$		5.41 cents/kWh	10 years or 30 000 hours' full load operation (FLO); fixed payment possible for plants < 2 kW
Small plants > 50 kW$_{el}$	50 - 250 kW$_{el}$	4.00 cents/kWh	30 000 FHU
	> 250 kW$_{el}$	2.40 cents/kWh	
New high-efficiency plants	< 50 kW$_{el}$	5.41 cents/kWh	30 000 FHU (for plants in emissions trading, the surcharge rises as of 1 January 2013 by 0.3 cents/kWh)
	50 - 250 kW$_{el}$	4.00 cents/kWh	
	250 kW$_{el}$ - 2 MW$_{el}$	2.40 cents/kWh	
	> 2 MW$_{el}$	1.80 cents/kWh	
Modernised/retrofitted high-efficiency plants (> 2 MW$_{el}$)	As for new high-efficiency plants	As for new high-efficiency plants	Max. 30 000 FHU (Plants < 50 kW$_{el}$: max. 10 years or 30 000 FHU)

Source: 2012 Cogeneration Act

Overall the calculations were based on 14 typical CHPP and their capacity parameters, costs and revenue. The data on individual plants in Table 9 were compiled in part on the basis of BHPP characteristics for 2014 (ASUE/BHKW-Infozentrum 2014) and verified with the help of experts and operators' and manufacturers' information. The data reported take account of the applications of the plant.

Table 9: CHPP considered

Plant:		**BHPP 1**	**BHPP 2**	**BHPP 3**	**BHPP 4**	**BHPP 5**	**ST 1**	**GT 1**
Network level		Low voltage			Medium voltage			
Size	kW$_{el}$	1	5	50	500	2 000	5 000	10 000
Investment costs incl. planning costs*	EUR$_{2013}$/kW	15 000	5 300	2 750	1 300	850	1 500	800
Efficiency rating - electrical	%	26 %	27 %	34 %	39 %	42 %	25 %	30 %
Efficiency rating - thermal	%	66 %	66 %	57 %	51 %	48 %	60 %	55 %
Efficiency rating - overall	%	92 %	93 %	91 %	90 %	90 %	85 %	85 %
Calculation period	a	10	10	10	15	15	15	15
Fixed operating costs	EUR$_{2013}$/kW$_{el}$,a	280	110	30	15	10	10	16

Variable operating costs	EUR$_{2013}$/MWh	60	40	25	13	9	8	6
Revenue from network user fees saved	EUR$_{2013}$/MWh	7	7	7	5	5	5	5
Plant:		**BHPP 6**	**G&S 1**	**G&S 2**	**G&S 3**	**G&S 4**	**Coal 1**	**Coal 2**
Network level		MV	High voltage					
Size	kW$_{el}$	10 000	20 000	100 000	200 000	450 000	400 000	800 000
Investment costs	EUR$_{2013}$/kW	700	1 300	1 300	1 200	1 100	-*	1 500
Efficiency rating - electrical	%	46 %	35 %	45 %	50 %	55 %	38 %	45 %
Efficiency rating - thermal	%	42 %	53 %	43 %	38 %	33 %	15 %	15 %
Efficiency rating - overall	%	88 %	88 %	88 %	88 %	88 %	53 %	60 %
Calculation period	a	15	20	20	20	20	20	20
Fixed operating costs	EUR$_{2013}$/kW$_{el}$,a	9	20	16	16	16	24	22
Variable operating costs	EUR$_{2013}$/MWh	6	4	1.8	1.5	1.5	3	2.5
Revenue from network user fees saved	EUR$_{2013}$/MWh	5	2	2	2	2	2	2

**Typical coal-fired CHPP from the 1980s; no newbuild considered for this type.*
Source: IFAM, BHKW-Consult, IREES, Prognos; MV= Medium voltage

4.2 Private households and CTS

All plants considered have in common that for the selected cogeneration applications, the net present value of the heat costs is illustrated over a selected period (given as real value in €$_{2013}$ net of VAT). The net present value of the heat costs of alternative heat production is given by way of comparison.

There are fundamental differences between CHPP which supply individual properties (residential buildings or CTS undertakings) and the cogeneration systems bound to the heating network in private household and CTS sector buildings.

4.2.1 District heating cogeneration

While it is possible with property cogeneration manages to specifically dimension various supply options for the examples used and to evaluate them in a cost-benefit analysis, it is nigh impossible to define typical heat selling systems for CHPP bound to the heating network as there is such a broad range of types of residential areas and imputable heat distribution costs in various local and district heating systems. That means that they would not be representative, as it would be impossible to generalise or transfer the findings. Therefore a cost-benefit analysis based on a particular CHPP makes little sense.

It makes more sense to analyse the individual supply cases across a large number of cases and them summarise the results. This has been done within the framework of the potential analysis in Chapter 5.1.1; the results obtained provide a meaningful picture of the cost-benefit analysis. It includes the effects of ongoing building renovation (see Section 5.1.1.5).

4.2.2 Property cogeneration

The purpose of considering individual properties in the private household and CTS sector is to compare the economic viability of various heat supply options based on the net present value of typical applications. In the residential sector, a BHPP is compared with a gas-fired boiler and with a smaller gas-fired boiler following thermal insulation of the building. Due to the low inlet temperatures, heat pumps are only suitable for low-temperature heating systems, which are rarely found in residential properties. Nonetheless, in order to estimate of the costs of heat pumps, various heat pump technologies are compared with a gas-fired boiler for two newbuilds (typical single-family house and apartment block).

As process heat requirements in the CTS sector vary enormously depending on the application and cannot be served either by heat pumps or by thermal insulation measures, the cogenerated heat supply option in the CTS sector is only compared to the alternative of heat supplied by a gas-fired boiler. For thermal insulation of buildings, large apartment blocks provide a good guide in terms of effects compared to a gas-fired boiler.

The approach taken to the individual heat supply options is described below, followed by a comparison and evaluation of the results.

4.2.2.1 BHPP supply option

Technical and economic parameters were laid down for six different BHPP size classes for the purpose of this project (see Table 9). As the sample properties to be supplied and their heat requirement do not exactly match one of those BHPP, compensation functions were established in a first stage for the following five parameters:

- cogeneration index;
- electrical efficiency rating;
- specific investment sum;
- specific fixed operating costs;
- specific variable operating costs.

The curves of these compensation functions can be found in Figure 61 to Figure 65 in the annex (Section 9.1.2). It is possible with the help of these curves to establish the values of the parameters needed for each BHPP sizing.

In the residential sector, four single-family houses and eight apartment blocks were selected for which costs for thermal insulation were available (see Section 4.2.2.2). In the CTS sector, the following three typical applications were formed:

- hospital with heat requirement of 2 000 MWh/a;
- office building with heat requirement of 100 MWh/a;
- commercial undertaking with heat requirement of 2 000 MWh/a;

The typical full load hours for the individual applications used to determine the maximum heat load can be found in Figure 74 in the annex (Section 9.1.2).

The selected plant capacity (relative to the maximum building heat load), the full load hours of the BHPP assumed and the percentage of private use of electricity can also be found in that figure. The building and plant parameters of the selected sample properties are given in Table 68 to Table 71 in the annex (Section 9.1.2).

The plant data defined thus are used, taking account of the cost and income positions given in Table 5, to calculate the net present value of heat production costs over
30 years from the economic and the business perspective.

4.2.2.2 Gas-fired boiler supply option

The net present values of heat production costs for a supply using a gas-fired boiler have been calculated as the reference variation. A gas-fired boiler is used as a reference, as that technology dominates in the heat supply to properties in Germany, especially in the building inventory.

As with the BHPP option, the net present values of the heat production costs are calculated over 30 years for operating a gas-fired boiler which provides the entire heat requirement of each property used as an example. The boiler is sized to 100 % of the peak load of the property supplied. The calculations have again been performed from both a business and an economic perspective.

4.2.2.3 Supply option with thermal insulation and a smaller gas-fired boiler.

[IWU, 2013] and [DENA, 2012] describe various measures for the sample properties investigated in the residential building sector to bring the building inventory up to a defined energy standard (e.g. efficiency house 55). Those measures apply to both the thermal insulation sector (e.g. facade insulation, triple glazing) and to plant technology (e.g. new heating ventilation systems with heat recovery). The costs of this are also given as additional energy costs, i.e. as the portion of overall costs incurred solely in order to improve the energy standard, not from maintenance[3]. Both the overall impact of all

renovation measures and the potential savings from individual measures are given.
Only individual measures to the building envelope are considered for the purpose of this comparison. Renovation measures, their additional energy costs and individual energy savings can be found in Table 72 to Table 74 in the annex (Section 9.1.2).

In the case of one-family houses, the renovation measures listed (together with plant technology measures not listed here) achieve a standard that exceeds the requirements of the Energy Savings Regulations by 30 %. In the case of multiple-family houses, however, the measures result in compliance with the *Efficiency house 55* standard. The renovation efficiencies achieved correspond on average to those of the trend scenario and thus those of the target scenario, which are broadly identical. The differences between the two scenarios are caused primarily by a different renovation rate; the target scenario assumes higher penetration.

It should be noted that the renovation measures selected are simply examples. It is not possible to make a comparison that is as unequivocal as the comparison between a CHPP and a gas-fired boiler. In practice, numerous combinations of various thermal insulation measures and of optimisation measures are conceivable in terms of plant technology to reduce the energy requirement (ventilation system, production of heat for heating). The standard chosen here is relatively high. Choosing a lower standard or individual, comparatively very effective measures would generate lower capital costs. Generally speaking it should be borne in mind there that implemented measures determine the energy requirement of a building over a period of approx. 30 years and should not therefore be set too low.

The aforementioned additional energy costs and the assumption that components have an average useful life of 30 years[4] are used to obtain the year-on-year costs. The costs of less heat production (smaller gas-fired boiler and reduced gas consumption) compared to an unrenovated building have been calculated in the same way as for the supply option using a gas-fired boiler to obtain the net present value of heating costs over 30 years.

4.2.2.4 Heat pump supply option

As already explained at the beginning of this chapter, heat pumps are only compared to natural gas heating for newbuilds. The basic parameters assumed can be found in Table 75 for one-family houses and in Table 76 for apartment blocks (both in the annex, Section 9.1.2). As newbuilds are investigated in each case, the costs of heating surfaces and flue are taken into account alongside the heat generator when considering the necessary investment.

In the case of a one-family house, both an air-water heat pump and brine-water heat pumps are taken into account, both in combination with an geothermal sensor (borehole) and a collector array. In the case of an apartment block, on the other hand, this was not investigated as there is generally no space available for a collector.

For both types of property supply, we calculated the net present value of heating costs for all supply options investigated over a period of 30 years. The price of electricity for the heat pumps is taken as 20 % lower than the domestic tariff (OP).

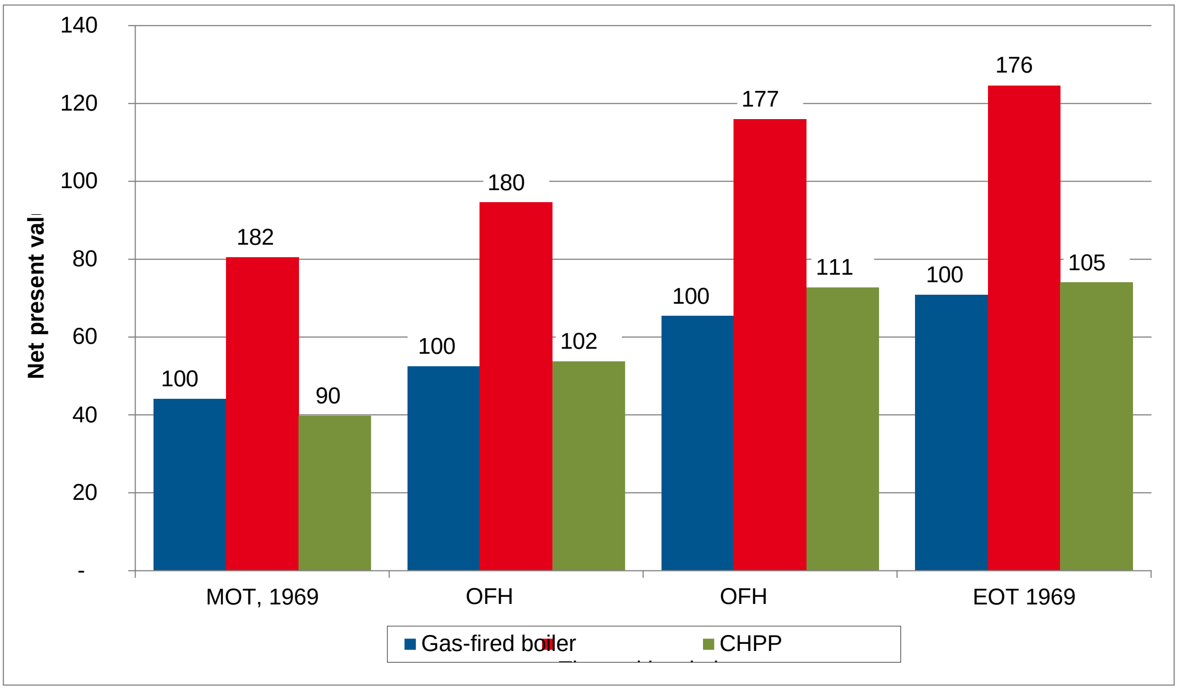
4.2.2.5 Results

The results of the supply options are presented below. The net present value of the overall costs of supplying the building with heat over 30 years is given. Thus a lower net present value represents a cheaper alternative.

BHPP supply option compared to a gas-fired boiler and thermal insulation – One-family house

Figure 2 compares the heat production costs of the three supply options for the four one-family houses considered from an **economic perspective**, i.e. disregarding relevant taxes and duty, based on an interest rate of 3 %.

Figure 2: Net present values of heat production costs for one-family houses from an economic perspective

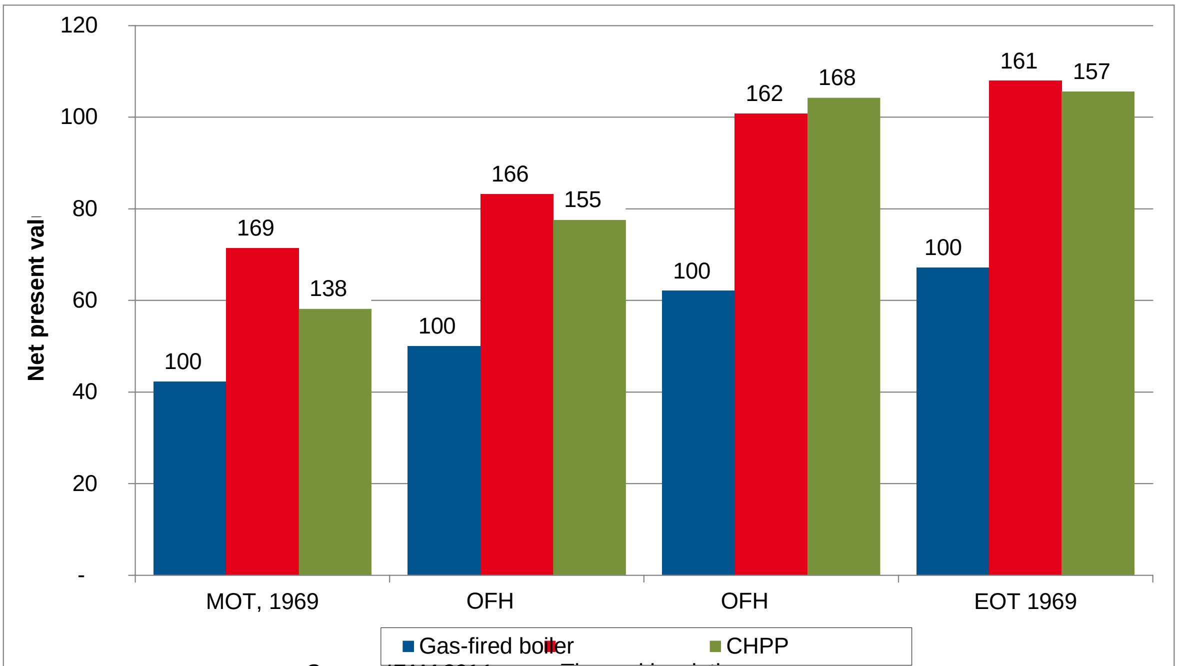


Source: IFAM 2014

For all sample properties investigated, heat supplied by a BHPP, compared to the gas-fired boiler option generates additional costs of between approx. 75 % and 80 %, primarily due to the very high specific investments in this capacity sector. The net present values of heat production costs for the thermal insulation option are more or less identical to those of a gas-fired boiler (between 90 % and 105 %). As regards the results obtained for thermal insulation for apartment blocks, it should be noted that they depend enormously on a series of factors. For example, an assumption with spiralling energy prices would make thermal insulation more cost-effective and, due to the high investment costs of thermal insulation measures, a lower assumed interest rate would align the net present values.

The results from a **business perspective** (i.e. taking account of all taxes and duty relevant to owners and an interest rate of 3 %) are presented in Figure 3.

Figure 3: *Net present values of heat production costs for one-family houses from a business perspective*



Source: IFAM 2014

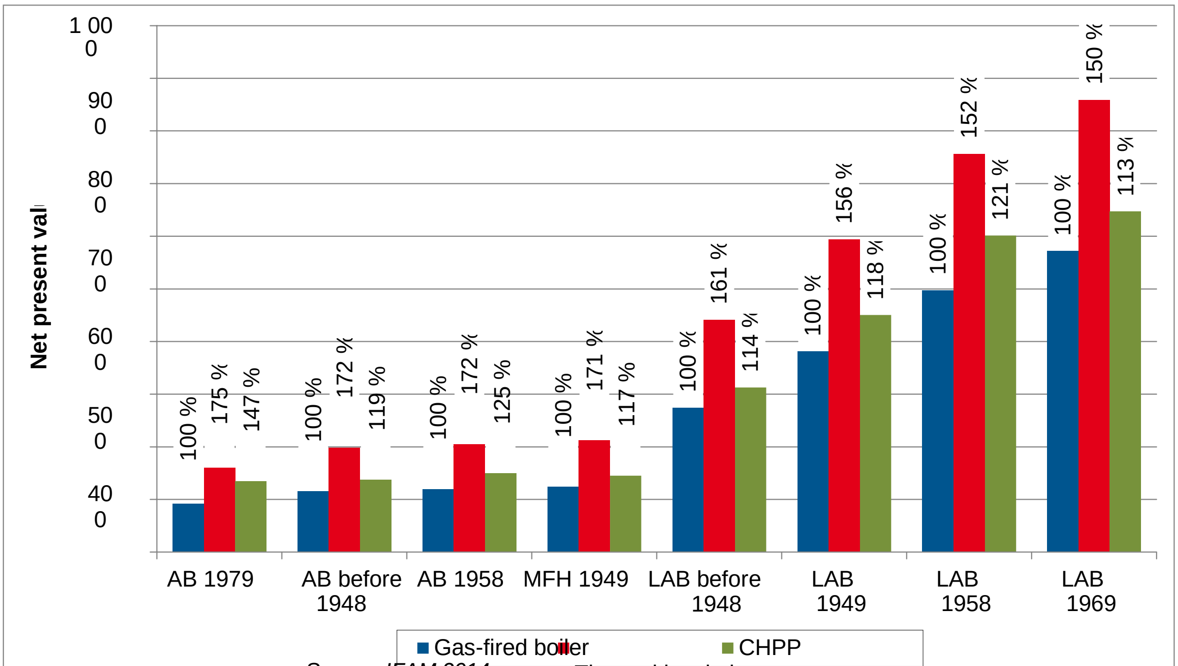
Here there is less of a difference between the gas-fired boiler and a BHPP; it is now between approx. 60 % and 70 %, as the cost savings made with the BHPP increase due to private consumption of the electricity generated. However, compared to the economic perspective, the economic viability of the thermal insulation option is much worse. This is due primarily to the enhanced interest rate, as a result of which the high initial investments weight far more heavily than the energy cost savings, which will only be felt over the course of time. If private investors had lower interest expectations than the 6 % used here, the net present values of the thermal insulation option would be in line or even better than for the gas-fired boiler scenario.

BHPP supply option compared to a gas-fired boiler and thermal insulation – Apartment block

The results from the **economic perspective** for the eight apartment blocks considered can be found in Figure 4.

Here again, the net present values of the BHPP options are higher than for the reference gas-fired boiler (between approx. 50 % and 75 %). Compared to the one-family houses, the BHPP perform better here, mainly due to the slightly lower specific investments. Again the thermal insulation options perform worse, although the difference is smaller here at between approx. 13 % and 50 %. It should be noted that the thermal insulation measures cannot be compared directly with measures for one-family houses due to the different sources and assumptions.

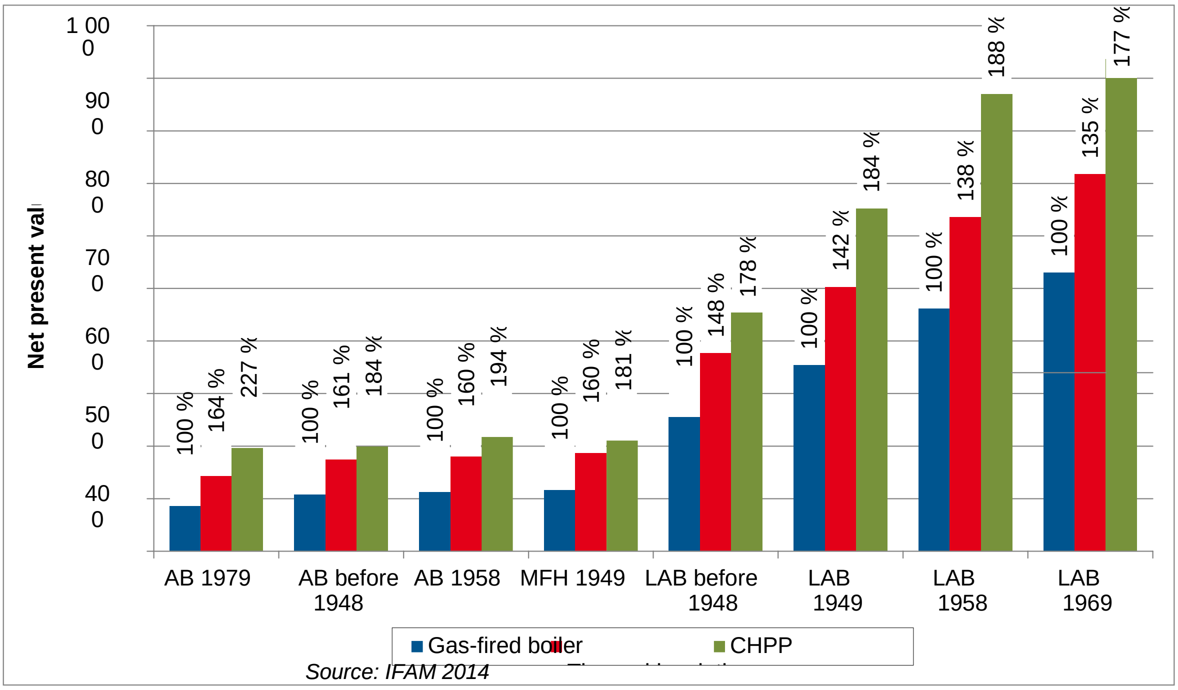
Figure 4: Net present values of heat production costs for apartment blocks from an economic perspective



Source: IFAM 2014

The results from a **business perspective** are presented in Figure 5. Here again a BHPP is more economically viable; however, the differences between that and the gas-fired boiler option are smaller than from an economic perspective, at between approx. 35 % and 65 %. One reason for this is that the rate of private use of electricity (10 %) is very low.
The net present values of the options with thermal insulation from a business perspective are between approx. 15 % and 45 % higher than for the gas-fired boiler options.

Figure 5: Net present values of heat production costs for apartment blocks from a business perspective



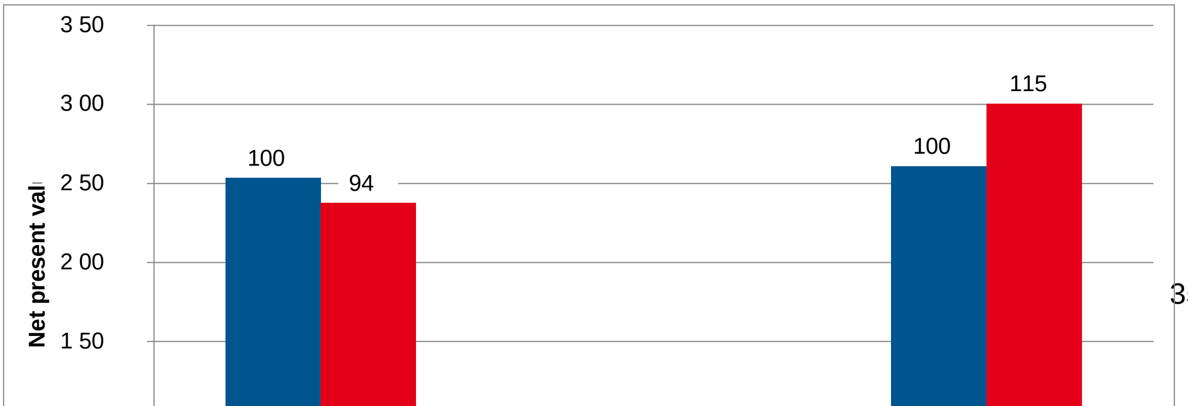
Source: IFAM 2014

BHPP supply option compared to a gas-fired boiler – CTS

Figure 6 illustrates the results for the selected CTS properties from an **economic perspective**.

Use of a BHPP is cheapest in the example of a hospital; the net present value is approx. 5 % lower than the alternative heat supply from a gas-fired boiler. The net present value for the other sample CTS properties with the BHPP option is approx. 55 % or 15 % higher than the gas-fired boiler option (office building/commercial business). It should be noted that the heat requirement of the building, the annual duration curve of that requirement and the rate at which the electricity generated by the BHPP can be used for private consumption are factors which have a considerable impact on the net present values (see Chapter 5.1.2.4 and Figure 74 in the annex in Section 9.1.2.

Figure 6: Net present values of heat production costs for CTS buildings from an economic perspective

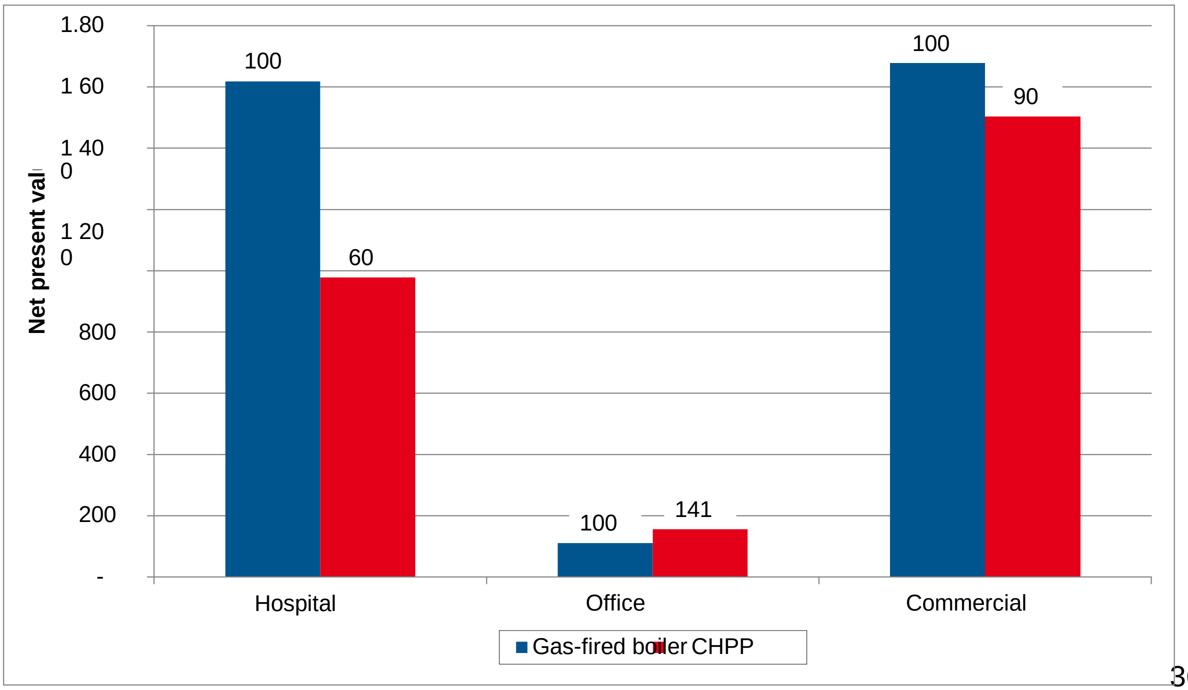


Source: IFAM 2014

Figure 7 illustrates the results from a **business perspective**. By far the cheapest option compared to a gas-fired boiler is a CHPP

in the hospital investigated (approx. 40 % better than the gas-fired boiler option). The least economically viable compared to a gas-fired boiler was the office building considered (approx. 40 % worse).
The net present value of the BHPP option for the sample commercial business was approx. 10 % lower than for the gas-fired boiler option. The high rate of private consumption in the hospital, together with the high number of full load hours, had a very positive impact on its economic viability. For the office building, the values for these two input data items were pitched much lower.

Figure 7: Net present values of heat production costs for CTS buildings from a business perspective



Source: IFAM 2014

Heat pump supply option compared to a gas-fired boiler – Newbuild residential building

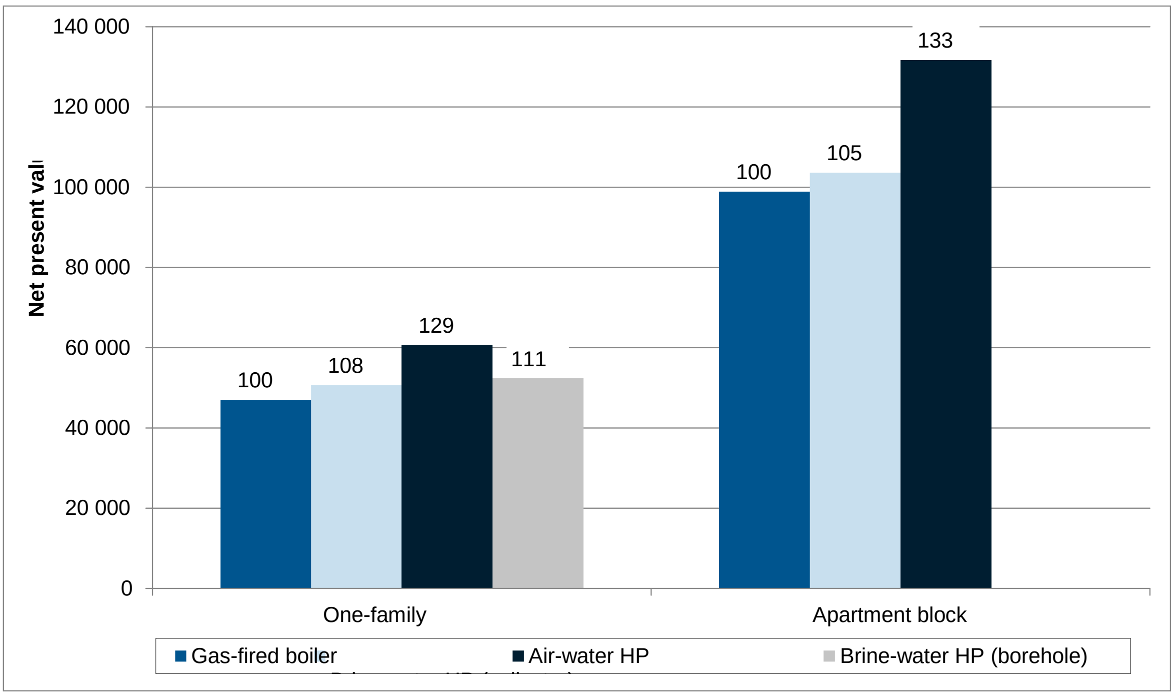
Figure 8 illustrates the net present values of the heat production costs of the various heat pump technologies compared to a gas-fired boiler from an **economic perspective** (left for a typical one-family house and right for a typical apartment block, both newbuilds).

A gas-fired boiler gives the best results for both the apartment block and the one-family house. The net present values of the CHPP options are higher than for the reference gas-fired boiler (between approx. 5 % and 35 %).

However, as in the previous cases, the result again depends in particular on the selection of basic data on changes in energy prices.

It would appear that the cheapest heat pump generates relatively low additional costs compared to a gas-fired boiler in relation to the BHPP comparisons investigated and, the smaller the building, the more that applies. It should be noted that this only applies to newbuilds.

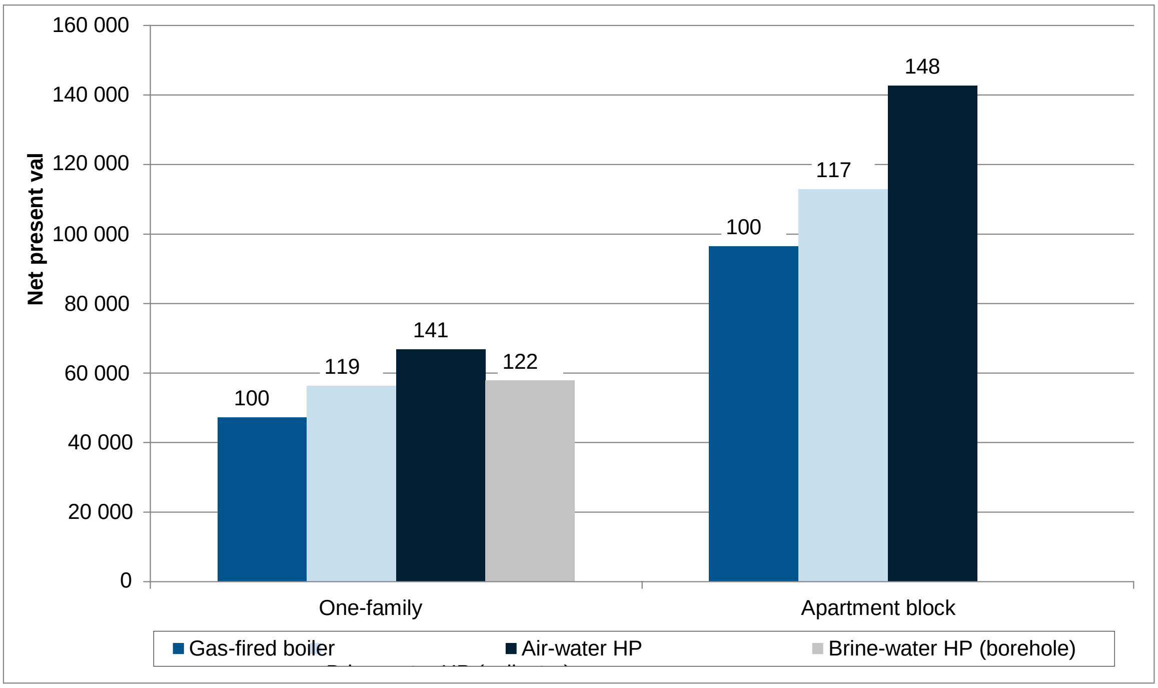
Figure 8: Comparison between net present values of heat production costs of heat pumps and a gas boiler from an economic perspective



Source: IFAM 2014

From a **business perspective**, the heat pump technologies are, relatively speaking, even less economically viable, as the initial investments weigh more heavily (see Figure 9).

Figure 9: Comparison between net present values of heat production costs of heat pumps and a gas boiler from an economic perspective



Source: IFAM 2014

4.2.3 Conclusion from results of cost-benefit analysis

We found for cogeneration for property supply that economically viable use of BHPP is not possible in the private household sector under the basic conditions assumed. This applies from both an economic and (to a lesser extent) business perspective. Due to the lower specific investment of costs of larger BHPP, larger apartment blocks perform better than smaller residential buildings.

In the CTS sector, the examples selected illustrated that the economic viability of BHPP depends enormously on the specific building. It is not possible to draw blanket conclusion as to the economic viability of types of heat requirements. For example, the sample hospital can be supplied more cheaply by a BHPP than a gas-fired boiler from both an economic and a business perspective. For the sample commercial undertaking, only the business perspective is cheaper than the gas-fired boiler option and, in the office building selected, a BHPP cannot be economically operated from either perspective. The investigations into the net present values of thermal insulation measures illustrate that, for the sample buildings chosen, thermal insulation has similar net present values as the gas-fired boiler option from an economic perspective. With the interest rates assumed in the business variation, the net present values of thermal insulation are much higher in all cases than for the options supplied by a gas-fired boiler. Here again, it is not possible to draw blanket conclusions, as the comparisons depend heavily on the state of the building prior to renovation, the measures implemented and other assumptions.

The evaluations of heat pump options for newbuilds (residential buildings) illustrate that the net present values of the various heat pump options are higher than the net present values of the reference supply using a gas-fired boiler (slightly to markedly from an economic perspective and considerably from a business perspective).

4.3 Industrial cogeneration

The objective of the cost-benefit analysis carried out here for industrial cogeneration was to calculate the electricity production costs and rate of return of typical plants which are relevant to industrial investors and plant operators and thus of fundamental importance to the analysis of the cogeneration potential of industry carried out at a later stage (see Section
5.2). Electricity production costs depend in part on the full load hours. In order to determine the economic viability of private generation in a CHPP, the electricity production costs were compared to the costs of purchasing electricity from third parties, which depend on the quantity purchased, the voltage level and the energy intensity, as well as the negotiating skills of the individual undertaking, which may vary within very wide margins.

Contrary to the economic viability calculations carried out in Section 7.5, here we only estimated the cost and price parameters available to the decision-maker. Thus we started with current energy prices, which we used to simulate the typical decision-making situation of an investor who does not know what future energy prices will be. This results arithmetically in a slightly lower rate of return than with a dynamic calculation with slightly rising energy prices over the calculation period.

Again contrary to the calculations in Section 7.5, a slightly higher required rate of return of 12 % was assumed, which reflects the return usually anticipated by industrial investors For the rest, the same pairs of capacity and cost parameters were assumed for the sample plants considered, thereby ensuring all the baseline data are consistent.

Aside from this business perspective, we also carried out our calculations from an ‘economic’ perspective, without energy taxes and levies on energy prices as defined previously. As a rule this depressed the rate of return due to the lack of price incentives, especially for alternative electricity purchases, and the lack of cogeneration fee.

4.3.1 Typification and characteristics of industrial CHPP

The electricity production costs and economic viability of industrial CHPP were determined by way of example for the following six types of plant from the business and the economic perspective:

- BHPP 50 kW_{el}
- BHPP 500 kW_{el}
- BHPP 2 MW_{el}
- Steam turbine 5 MW
- Gas turbine 10 MW
- Gas and steam turbine plant 20 MW

The characteristics listed in Table 10 and used for the calculations were reconciled with the VIK [Verband der Industriellen Energie- und Kraftwirtschaft e.V.] and checked for plausibility. They are one element of the uniform rate used in this investigation for plant characteristics.

Table 10: Characteristics of CHPP types and capacities analysed in industry

Designation/Type of plant	Unit	Block heat and power plant			Steam turbine	Gas turbine	Gas and steam turbine
Size of plant (el.)	kW / MW	**50 kW**	**500 kW**	**2 MW**	**5 MW**	**10 MW**	**20 MW**
Network level	Voltage	LV	MV	MV	MV/HV	MV	HV
Application	-	Property cogeneration	Property cogeneration,	DH, industry	industry	industry	Industry, DH
Investment costs incl. planning costs	Euro2013 / kW	2 750	1 300	850	1 500	800	1 300
Lifetime	years	10	10	15	15	15	15
Efficiency rating - electrical	%	34 %	39 %	42 %	25 %	30 %	35 %
Efficiency rating - thermal	%	57 %	51 %	48 %	60 %	55 %	53 %
Overall efficiency rating	%	**91 %**	**90 %**	**90 %**	**85 %**	**85 %**	**88 %**
Fixed operating costs	Euro2013 / kW_{el}, a	30	15	10	10	16	20
Variable operating costs	Euro2013 / MWh_{el}	20	13	9	8	6	4
Revenue from network user fees saved	Euro2013 / MWh_{el}	7	5	5	5	5	2
Cogeneration Act cogeneration surcharge	Cent / kWh	5.41	3.34	2.64	2.43	2.27	2.18

Source: IREES, our assumptions; VIK 2014 pers. information

4.3.2 Methodology and energy prices

The economic viability calculations for the six types of plant considered were carried out based on the plant characteristics given in Table 10 using the method described in detail in the annex.

Rate of return from a business perspective

The difference between the costs of the energy generated by a CHPP (electricity, heat) compared to the costs for uncoupled/purchased electricity is the only parameter that determines the economic viability of a CHPP.

A CHPP is considered to be economically viable if the costs of buying electricity from a third party are higher than the electricity production costs of the CHPP. The electricity production costs illustrate the expenditure needed in order to generate one kilowatt hour of electricity. They have to be evaluated in relation to the reference electricity price or in connection with the spot electricity price.

Electricity production costs in this study take account of total costs incurred and revenue generated in operating the CHPP. These costs and revenue include:

- fixed operating costs, which vary from one CHPP to another;
- variable operating costs, which vary from one CHPP to another and depending on capacity;
- annualised investments (capital costs) for each type of CHPP and capacity;
- annual fuel costs incurred;
- the levies payable for private use of electricity (these costs are not generally included in electricity production costs) and
- the revenue to be generated. Revenue also takes account of effective cogeneration subsidies, the network user fees saved and the corresponding heat credits.

However, blanket conclusions as to the economic viability of CHPP in industry based on typification by capacity and technology can only be drawn to a limited extent. That is because the operating circumstances in terms of individual production structures, the size of the undertaking and the amount and structure of energy consumption may vary enormously within the same branch. In particular, the electricity prices with which private production in a CHPP must compete vary considerably; that is because they are negotiated, with some electricity being purchased through groups or groupings and some being purchased via the exchange.

It is possible to draw relatively sound conclusions as to the electricity production costs of specific technologies based on fundamental parameters such as annual full load hours. To simplify matters, the electricity prices payable by industrial customers, with which production costs are compared, were established for seven examples (IND1 TO IND7). They were classed based on annual quantities purchased and assumptions as to the typical network level of the supply point (‘network level’), which determines the network user fee.

The facility for electricity-intensive companies to make a claim under the compensation scheme laid down in the RES Act was considered as further difference. To simplify matters, it was assumed that this was only open to IND6 and IND7 (annual quantity purchased > 100 000 MWh at high voltage level).

We basically assumed that industrial customers claim electricity tax relief and tax capping on quantities purchased > 1 000 MWh/a (IND3 to IND7). That gave the industrial electricity prices listed in Table 11. The value used for the calculation from a business perspective (top row) and the value corrected for taxes and levies used for the calculation from an economic perspective (bottom row) are listed for each category.

Cost-benefit analysis from economic perspective

The cost-benefit analysis from an economic perspective means the analysis of residual energy prices net of any taxes, duty and levies (RES and cogeneration levies). Thus the fuel used has no energy tax and the quantities of electricity purchased have no electricity tax and RES and cogeneration levies are disregarded.

However, that definition of a cost-benefit analysis from an economic perspective has the disadvantage that the prices do not take account of changes to the energy system pursued under energy and climate policies towards more renewable energies and cogeneration and the underlying desire to avoid high adaptation costs and damages in future.

Table 11: Industrial electricity prices by consumption class including/excluding apportioned costs and taxes ('business perspective'/'economic perspective') up to 2050, net of VAT

		Network level	Perspective[5]	2013	2014	2020	2030	2040	2050
Industry 1, (light industry), 0.05 GWh per annum	Cent2013/kWh	LV	B	19.3	19.8	21.3	20.7	20.5	20.5
			E	11.8	11.4	12.4	15.0	16.8	17.4
Industry 2, (SME), 0.2 GWh per annum	Cent2013/kWh	LV	B	18.7	19.1	20.7	20.1	19.9	19.8
			E	11.6	11.2	12.2	14.8	16.6	17.2
Industry 3, (SME), 1			B	15.7	16.1	17.5	17.4	17.1	17.0

GWh per annum	Cent2013/kWh	MV	E	9.3	8.9	9.8	12.3	14.0	14.6
Industry 4, 10 GWh per annum	Cent2013/kWh	MV	B	14.0	14.6	16.0	15.5	15.2	15.1
			E	7.9	7.7	8.5	11.0	12.8	13.4
Industry 5, 100 GWh per annum	Cent2013/kWh	HV	B	11.0	11.9	13.1	12.3	11.9	11.6
			E	5.4	5.5	6.1	8.6	10.1	10.6
Industry 6, 100 GWh per annum, reduced network fees	Cent2013/kWh	HV	B	4.5	4.5	4.9	7.3	8.8	9.2
			E	4.1	4.2	4.6	7.0	8.5	8.9
Industry 7, 1000 GWh per annum, reduced network fees	Cent2013/kWh	HV	B	4.1	4.1	4.5	6.9	8.4	8.8
			E	3.9	3.9	4.3	6.7	8.2	8.6

Source: Prognos 2014

4.3.3 Results economic viability calculation for CHPP

The results of the economic viability calculation for the six industrial CHPP cases considered from a business perspective are presented in the typical curves of sinking electricity production costs as a function of the number of full hours' load assumed (between 2 000 h/a and 7 000 h/a) (see Figure 10 to Figure 15). The electricity production costs determined are compared to average reference electricity prices deemed typical for an undertaking using the particular cogeneration technology. Several reference electricity prices which reflect the range of variation for the situation in each undertaking (e.g. special compensation rule under the RES Act, two-shift to four-shift operation, well or less well negotiated electricity prices, relatively consistent or inconsistent electricity acceptance range etc.) are used as reference values. If the electricity production price is higher than the reference prices given, as a rule that indicates that the plant in question cannot be operated profitably under the given constraints.

In each case a distinction is drawn between the 'business' and the 'economic' perspective (see Section 4.

BHPP 50 kW$_{el}$

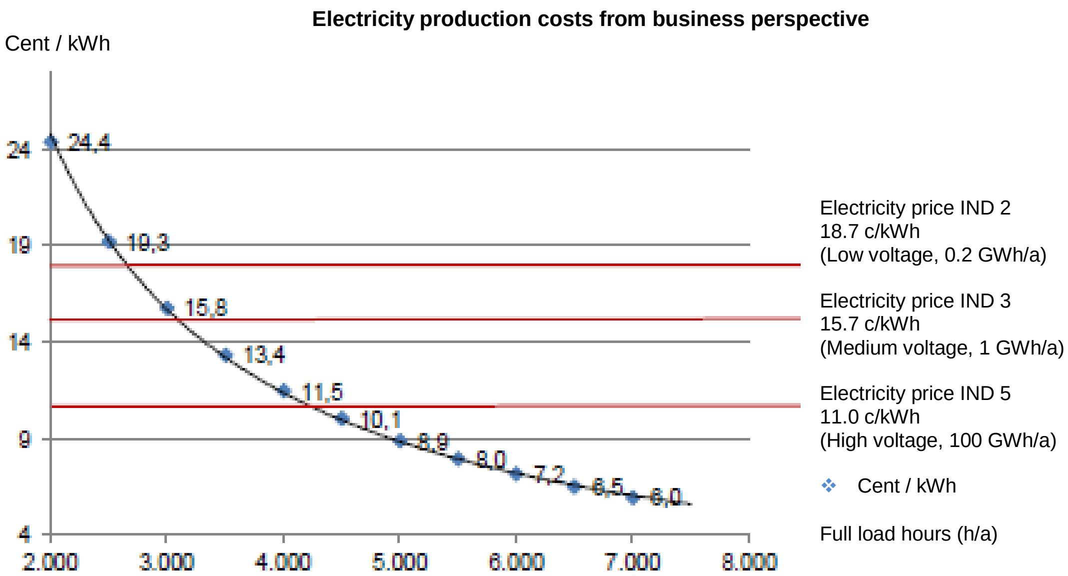
It should be noted that BHPP with electrical rated capacity of 50 kW$_{el}$ for low voltage customers with over 2 500 (full load) hours a year must work at full capacity if they are to be operated profitably. They must be operated at much higher capacity utilisation in order to compete under current constraints against low electricity prices for industrial customers in the medium voltage network.
(see Figure 10). With high specific investments and the resultant high fixed costs, that depends on their receiving the highest cogeneration levies applicable for plants of this size. This type of plant can only be considered rarely for large industrial consumers with very low electricity prices. Even for property heating and cooling and hot water supply, high capacity utilisation (at least 3 000 hours) must be

guaranteed Technical options to increase capacity utilisation in heat-operated processes include integration into heating networks, where applicable with integrated heat storage facilities, or use of excess heat to produce refrigeration (absorption refrigeration).

As electricity prices rise, CHPP may be expected to become more economically viable.

From an economic perspective (which disregards cogeneration subsidies) the results for private consumption in cogeneration deteriorate. Only with much higher capacity utilisation does private production have an advantage over electricity purchases. However, it must be noted that this perspective disregards the benefits of primary energy savings and external effects prevented, especially the CO_2 emissions saved. However, that presentation illustrates that, if cogeneration is to be developed for energy and climate policy reasons, effective subsidies are also needed for these small industrial plants.

Figure 10: 'Business' and 'economic' electricity production costs of a BHPP with 50 kW_{el} capacity as a function of full load hours in 2013



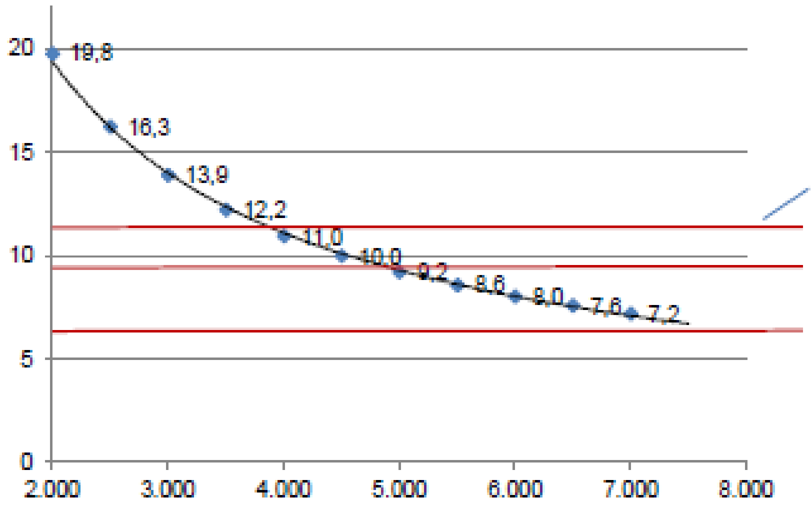
Electricity production costs from economic perspective

Cent / kWh

Electricity price IND 2
11.6 c/kWh
(Low voltage, 0.2 GWh/a)

Electricity price IND 3
9.3 c/kWh
(Medium voltage, 1 GWh/a)

Electricity price IND 5
5.4 c/kWh
(High voltage, 100 GWh/a)



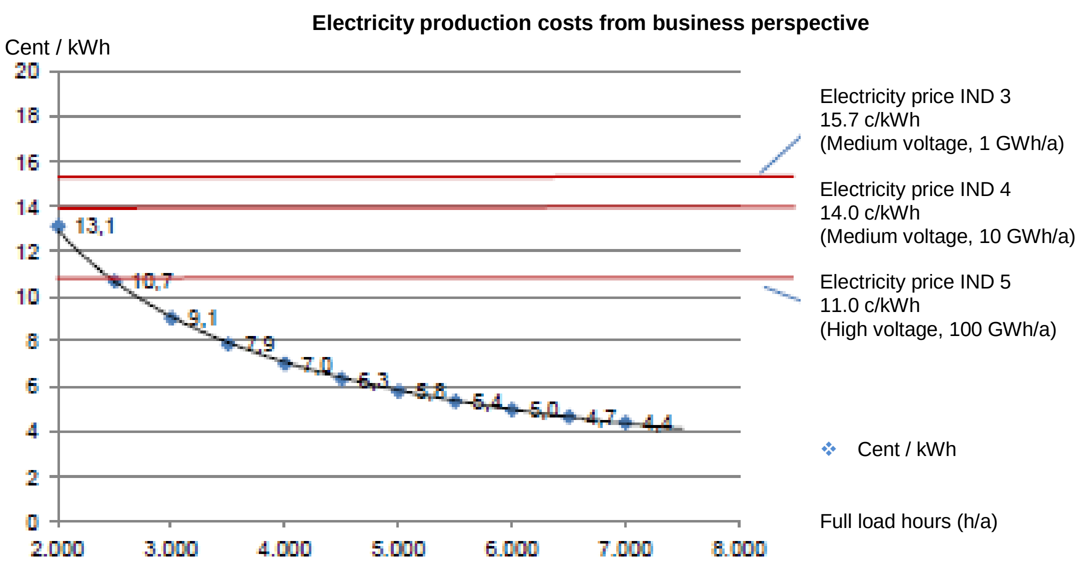
Source: IREES 2014

BHPP 500 kWel

As BHPP with electrical rated capacity of 500 kWel have considerably lower specific investments, the results compared to smaller plants are much better, although when these are compared to against electricity purchases, low electricity prices must be assumed for potential investors (large undertakings) (see Figure 11). Thus, even medium-sized businesses might be tempted to operate such a CHPP with as little as 2 500 full load hours a year. Based on the sizes of undertaking assumed, a higher heat requirement base load must also be assumed, which will enable a higher number of full load hours to be achieved.

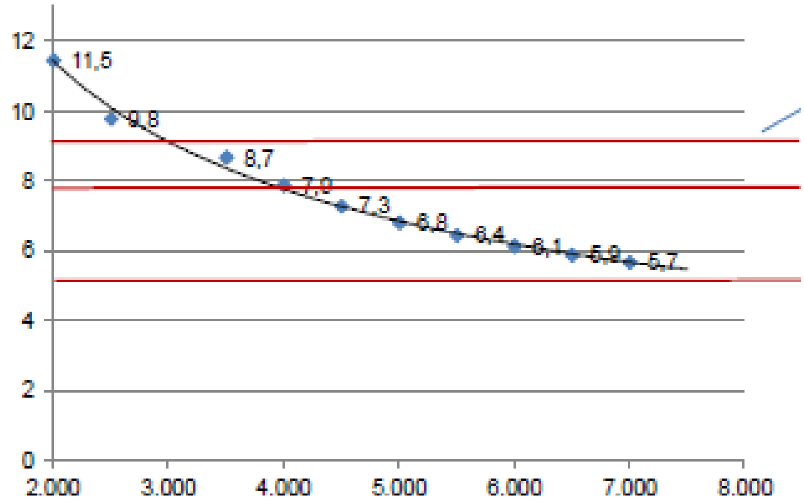
As electricity prices rise over time, this type of plant can also be expected to offer an increasing cost benefit to operators.

Figure 11: 'Business' and 'economic' electricity production costs of a BHPP with 500 kWel capacity as a function of full load hours in 2013



Electricity production costs from economic perspective

Cent / kWh



Electricity price IND 3
9.3 c/kWh
(Medium voltage, 1 GWh/a)

Electricity price IND 4
7.9 c/kWh
(Medium voltage, 10 GWh/a)

Electricity price IND 5
5.4 c/kWh
(High voltage, 100 GWh/a)

Cent / kWh

Full load hours (h/a)

Source: IREES 2014

BHPP 2 MW$_{el}$

Despite **lower** electricity production costs, due in part to the price digression of the specific investment, the comparison with the assumed reference electricity prices for BHPP with electrical rated capacity of 2 MW is slightly less favourable than with a small plant (500 kW), as potential investors must be expected as a rule to enjoy more favourable electricity prices (see Figure 12). This applies in particular where the undertaking has a high voltage connection or benefits from the compensation rule under the RES Act for electricity-intensive undertakings (IND6).

As a rule, this size of plant can be profitably operated at over 3 000 full load hours a year.

Figure 12: 'Business' and 'economic' electricity production costs of a BHPP with 2 MW$_{el}$ capacity as a function of full load hours in 2013

Electricity production costs from business perspective

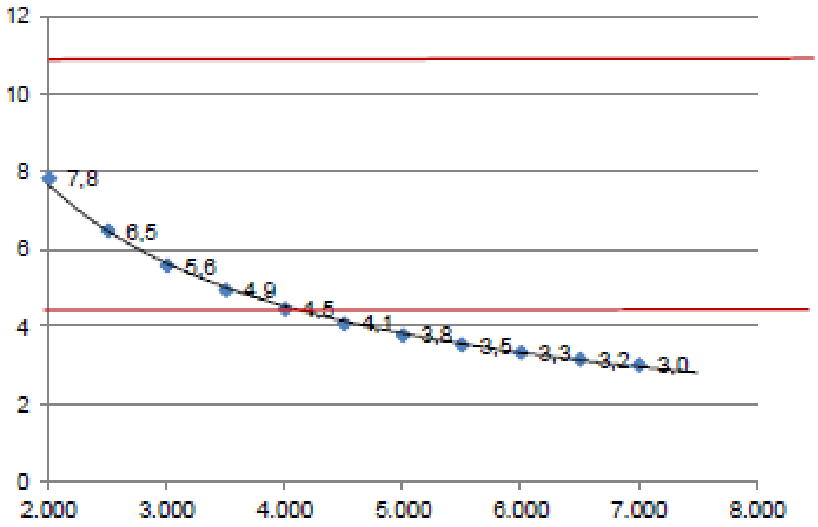
Cent / kWh

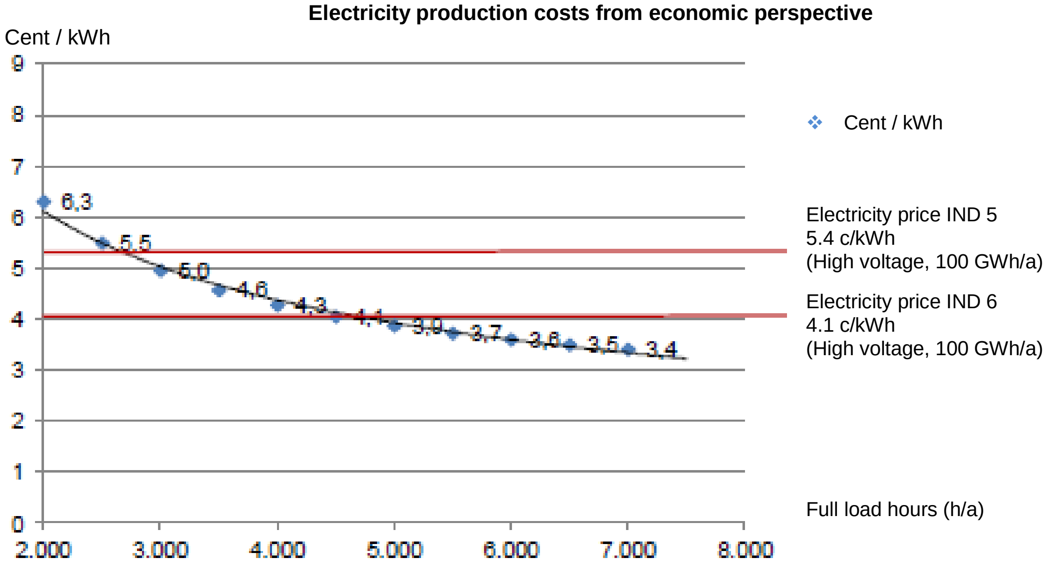
Electricity price IND 5
11.0 c/kWh
(High voltage, 100 GWh/a)

Electricity price IND 6
4.5 c/kWh
(High voltage, 100 GWh/a)

Cent / kWh

Full load hours (h/a)





Source: IREES 2014

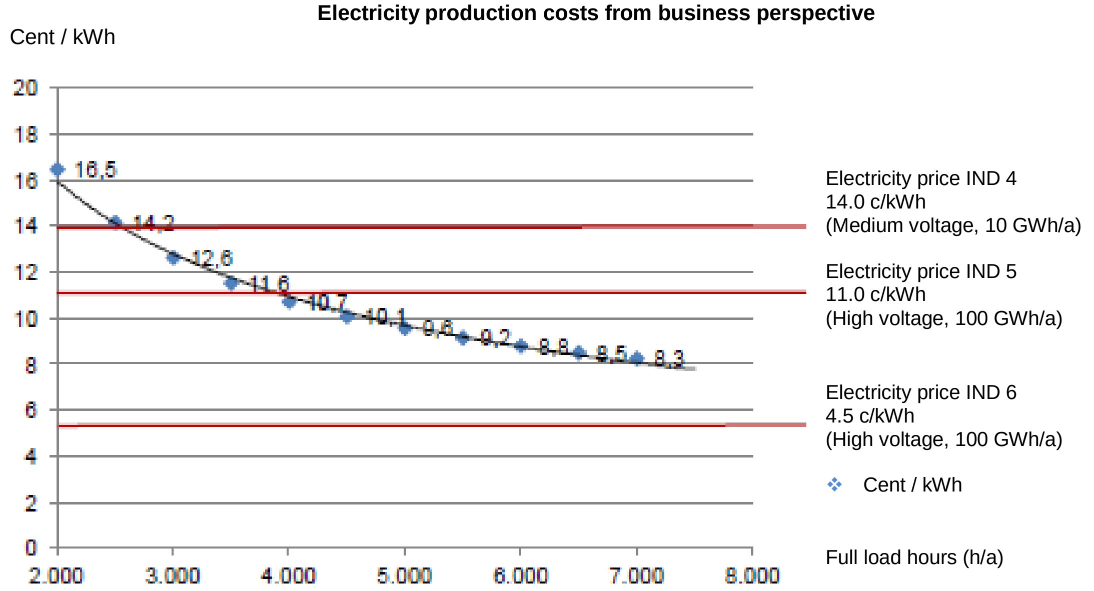
Steam turbine 5 MW_{el}

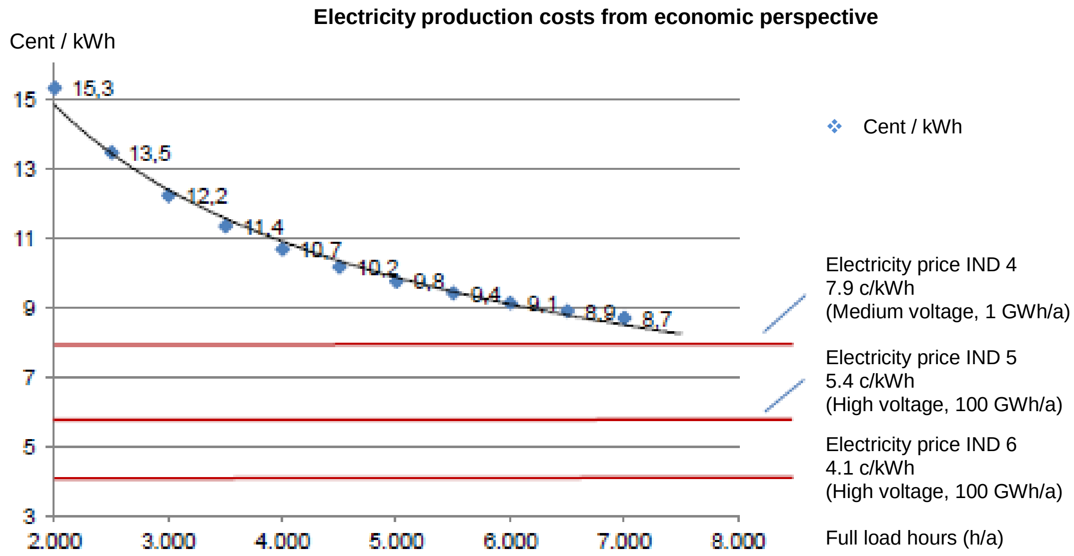
Steam turbines with electrical rated capacity of 5 MW are a capital-intensive technology. Despite longer depreciation periods (15 years), the high specific investment gives rise to relatively high fixed costs. The electricity production costs therefore often cannot compete with electricity prices in the case of large undertakings with a high voltage connection which enjoy cheap electricity prices. With a reference electricity price of 11 cents/kWh (IND5), which may be quite frequent, such plants can only be operated profitably over 4 000 full load hours. With lower reference prices, this type of plant will not be used unless production- or location-related conditions dictate otherwise (see Figure 13).

As, based on this level, the reference electricity price in absolute values only rises slightly comparatively speaking, the anticipated future change in this situation is marginal.

From an economic perspective, the comparison with electricity purchases much less favourable for private consumption, which suggests that BHPP will continue to need subsidies if this type of plant is to achieve broad diffusion.

Figure 13: 'Business' and 'economic' electricity production costs of a steam turbine with 5 MW_{el} capacity as a function of full load hours in 2013





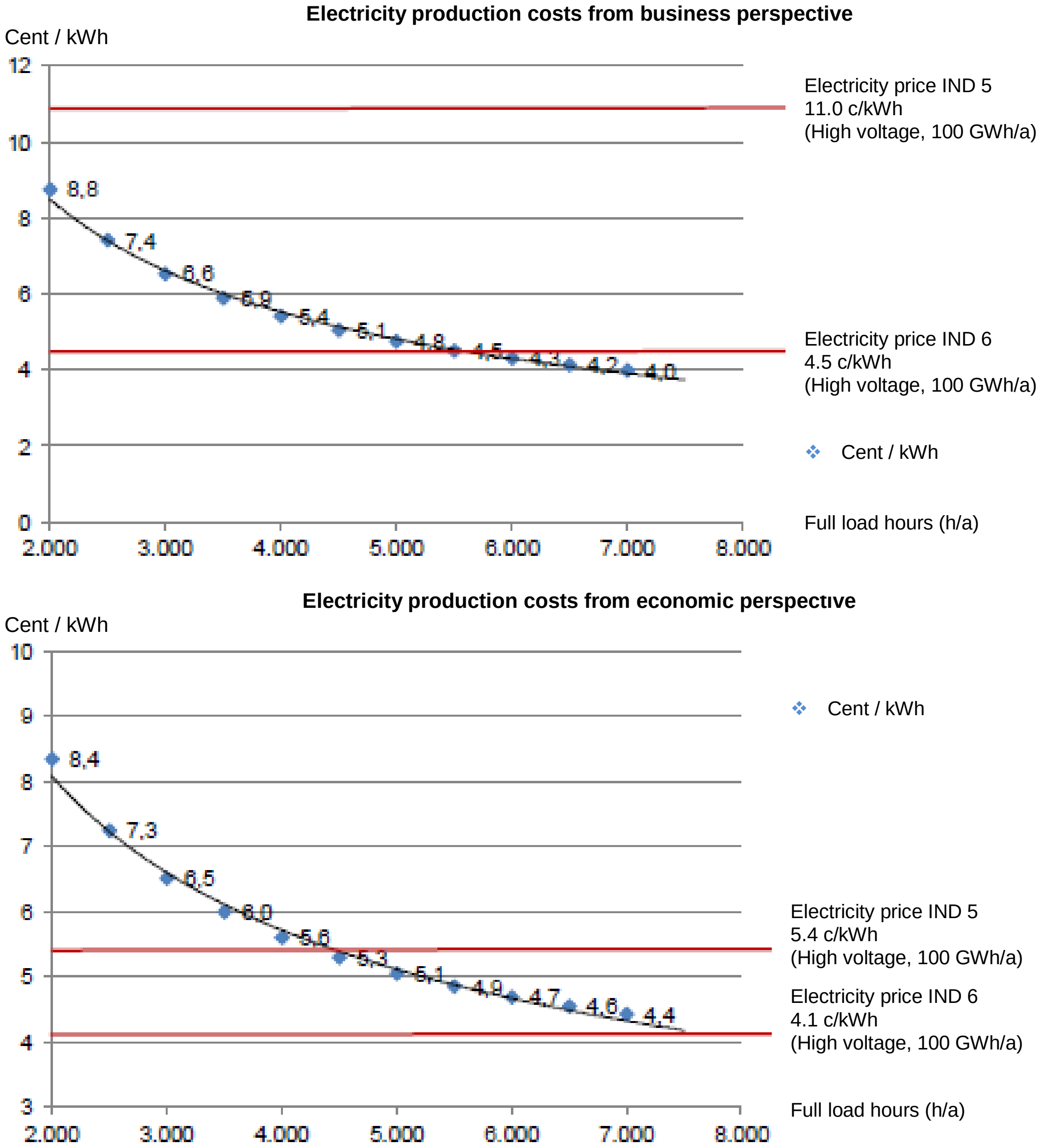
Source: IREES 2014

Gas turbine 10 MW_{el}

For gas turbines with electrical rated capacity of 10 MW, much lower specific investments are assumed than for steam turbines. They result in electricity production costs which, in many instances, result in a positive result in favour of private generation (see Figure 14).

However, the ratio of levies to the assumed reference electricity price for IND5 is still relatively high; as a result, the comparison from an economic perspective in this case comes out in favour of electricity purchases up to approx. 4 500 full load hours. Compared to IND6, the gas turbine considered here always performs worse from an economic perspective.

Figure 14: ‘Business’ and ‘economic’ electricity production costs of a gas turbine with 10 MW_{el} capacity as a function of full load hours in 2013



Source: IREES 2014

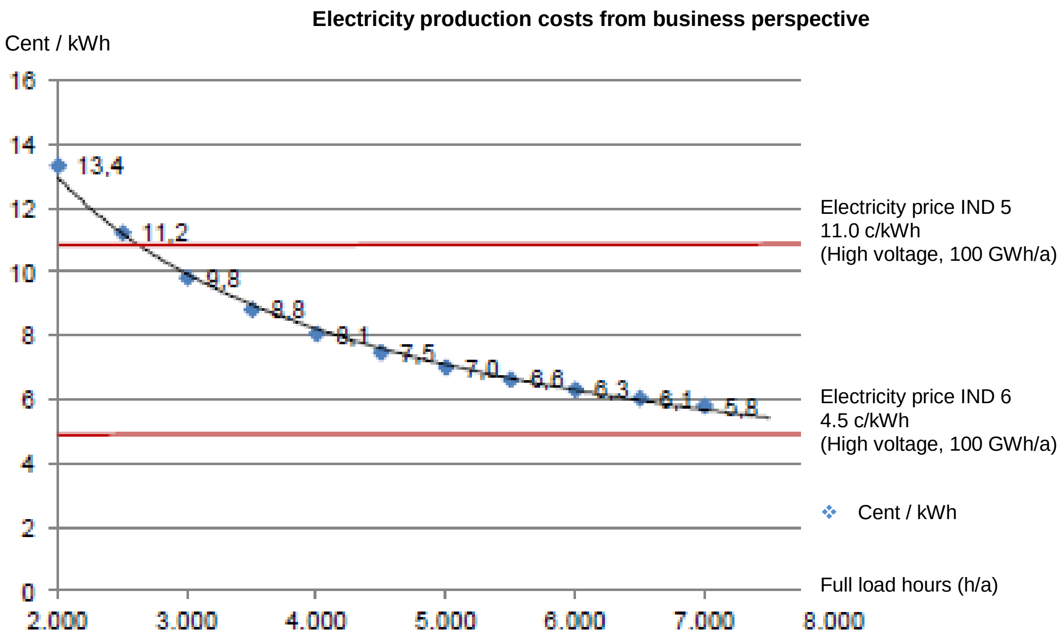
Gas and steam turbine 20 MW_{el}

Gas and **steam turbine plants** with overall electrical rated capacity of 20 MW are similar to steam turbine plants in that they are a capital-intensive technology with very high fixed costs. The electricity production costs in this example are reduced by the effective cogeneration surcharges by around 1 cent/kWh; they therefore cannot compete with electricity prices in the case of large undertakings with a high voltage connection which enjoy extensive relief on RES levies and thus very cheap electricity prices (less than 5 cents/kWh (IND6) (see Figure 15).

As, based on this level, the reference electricity price in absolute values only rises slightly comparatively speaking, the anticipated future change in this situation is marginal.

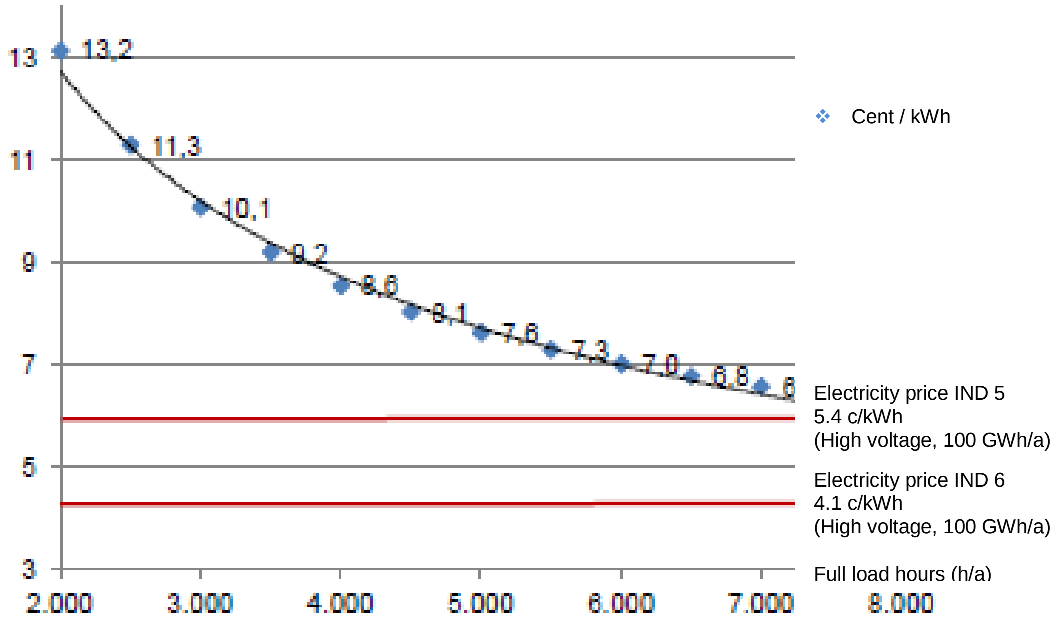
As the production costs from an economic perspective only change slightly, but the reference electricity price for IND5 includes considerable relief from levies, a 20 kW G&S plant in this category also falls outside the profitability zone. Thus even these high-efficiency combined plants also need subsidies.

Figure 15: 'Business' and 'economic' electricity production costs of a gas and steam turbine with 20 MW_{el} capacity as a function of full load hours in 2013



Electricity production costs from economic perspective

Cent / kWh



Source: IREES 2014

4.3.4 Economic viability of trigeneration

Thermal refrigeration production is an interesting option for industry in Germany in terms of energy efficiency, especially where cheap sources of heat are available. Various systems are available for absorption refrigeration production (Henning et al., 2009; Henning et al., 2011; Safarik, Richter & Albring, 2010; Green Chillers, 2010; Schmid, 2011; Verband für Sorptionskälte e.V., 2014).

Electricity-intensive compression chillers can be replaced in part or even in full by absorption chillers. Both the solar heat in industrial processes often cited as a heat source for these plants and, in particular, waste process heat can be used. Cogenerated heat can also be used (trigeneration). Trigeneration increases the capacity utilisation of CHPP, especially in the summer months, when the demand for heat for heating and hot water falls. In beneficial cases, this may compensate for the effect of the high investments still needed at present in absorption chillers. If the use of cogeneration is increased for industrial refrigeration production in the investment goods, commodities and consumer goods industry, absorption refrigeration should be able to reduce overall energy costs more frequently.

Compared to conventional compression chillers, water-lithium bromide absorption chillers still have higher specific capital costs. Therefore these plants have only been used in one-off instances to date, mostly in combination with 'conventional' compression chillers, for example for air-conditioning and to provide process refrigeration at minimum capacity.

Examples of this are plants in the chemical industry or foodstuffs industry or to air-condition large government buildings, some of which are operated by contractors. Such plants are supplied primarily from cogeneration and industrial waste heat available throughout the year.

The increasing use of cogeneration and the increasing use of industrial waste heat will most probably drive an increase in the market share of absorption refrigeration technology. It can therefore be assumed that this technology will gain in market importance and that the potential for technical development and cost reductions can be realised in full. However, these can only be quantified to a limited extent within the framework of this study. However, an evaluation from an economic perspective cannot be limited to refrigeration production technology alone (absorption versus compression chillers) and must always include the overall power and heat production system.

4.3.5 Economic viability of ORC plants

The organic ranking cycle process is a thermodynamic cycle which uses organic substances with a low boiling point as its working medium. Thus, unlike the steam turbine process in thermal power plants which use water as their working medium, power can be generated from heat sources at lower temperatures. A distinction can be made between low temperature plants which use heat sources > approx. 90 °C and high-temperature plants which use heat at temperatures > 450 °C The heat sources may be ground heat, waste heat from use of biomass, industrial waste heat etc.

According to information from ORC Fachverband e.V, ORC technology proves its worth in the electrical capacity range of 500 to 2 000 kW_{el} and approx. 150 ORC plants have been installed in Germany to date. There are an estimated 20 plants in Germany at present which use industrial waste for power production. Many of these are pilot plants.

One of the advantages of turning industrial waste heat into electricity is that the proximity of production and consumption can be exploited in industrial regions, thereby obviating the need for long-distance transport.

The economic viability of electricity production from waste heat may be improved by the fact that the costs of process cooling which would otherwise be needed can be saved. As a rule, the higher the temperature of the heat source available, the better the rate of return on an ORC plant. At temperatures > 400 °C, it is reported that electricity can be produced at less than 10 vent/kWh (ORC-Fachverband 2014 a, b).

4.3.6 Conclusion from economic viability analyses

The economic viability calculations for the six types of industrial CHPP considered here by way of example illustrate the importance of current cogeneration subsidies to the rate of return from a business perspective. This is especially clear for the smallest type of plant considered (BHPP with 50 kW_{el}. (Electricity production costs with and, in one calculation, without the cogeneration surcharge are presented in the annex in order to illustrate the importance of cogeneration subsidies.)

With higher capacity, the rate of return in private generation in a CHPP is often undermined from a business perspective by the low electricity purchase costs which must be assumed for the larger, energy-intensive undertakings that operate such plants or would invest in such plants.
This applies in particular to large, power-intensive undertakings that enjoy relief on electricity tax (tax capping) and extensive relief on the RES levy. This is especially clear in two cases considered (steam turbine with 5 MW_{el} and G&S power plant with 20 MW_{el}), both of which are plants which require large investments, resulting in relatively high capital expenditure.

The economic viability comparisons for the types of plants selected suggests that growth of industrial cogeneration will be driven primarily in future by BHPP and gas turbines. This is an important piece of information for the potential estimates based on them.

Taxes and duty are disregarded from the economic perspective. As a result, industrial CHPP tend to have an even lower return on investment than from a business perspective. However, the beneficial effects of primary energy savings and the reduction in CO_2 emissions are excluded.

The rate of return on CHPP increases if refrigeration is also produced using absorption technology; this use of cogenerated heat therefore represents one way of improving the capacity utilisation of the plant.

There are at present only a few ORC plants in industry which generate power from waste heat. If the existing potential for development is tapped, however, perfectly profitable applications would be possible in future, especially for hotter waste heat.

5 Potential analysis

The potential analysis is based on the results of the cost-benefit analysis and illustrates the potential changes in quantities that may result for Germany as a whole.

Private households and CTS

Work to determine the **potential of grid-bound cogeneration** was based on the methodology of detailed analysis of 41 representative model towns and transfer of their results to comparable towns. The heat requirement was extrapolated with due account for the effects of renovations and newbuilds. The model towns are subdivided based on their settlement structure into a total of
1 403 clusters. The economic viability of cogeneration is investigated for each individual cluster, once from an economic and once from a business perspective. Two connection rates (CR) are investigated in each case (90 % and 45 %). The results of the first scenario are given in Table 1.

Table 12: District heating cogeneration potential (scenario CR 90)

Perspective	District heating cogeneration potential	TWh
business	Heat demand	154
	Cogenerated heat production	128
	Cogenerated power production	113
economic	Heat demand	249
	Cogenerated heat production	207
	Cogenerated power production	182

Source: IFAM 2014

With the reduced connection rate of 45 %, the potential drops to approx. one-quarter. The results are highly sensitive; slight changes to basic parameters clearly change the results. Around half the potential is accounted for by towns in the old federal states with over 150 000 inhabitants.

The potential of **property cogeneration** is based on a full cost comparison with a gas boiler for eight typical applications. Only the buildings in the model towns outside economic district heat cogeneration clusters are considered in each scenario are considered, in order to avoid counting them twice in the district heat cogeneration potential. The results are shown in Table 2.

The values from an economic perspective are much lower for two reasons: the ‘success rate’ of the partial quantities investigated is much lower and the (cluster) quantities available are considerably smaller. The rate of private use of electricity is of vital importance. The higher that rate, the more economically competitive the CHPP.

Table 13: Property cogeneration potential (scenario CR 90)

Perspective	District heating	TWh
business	Heat demand	33
	Cogenerated heat production	21
	Cogenerated power	14
economic	Heat demand	5
	Cogenerated heat production	3
	Cogenerated power	3

Source: IFAM 2014

With a reduced district heating connection rate of 45 %, the quantities available increase and the potential almost doubles.

The potential analysis is based on the results of the cost-benefit analysis, e.g. on the heat production costs of CHPP and gas-fired boilers. Whereas the cost-benefit analysis is used to calculate typical sample cases, the potential analysis broadens those prospects and suggests the resultant quantities for Germany as a whole. The potential calculated can be compared in the individual sub-sectors with the status quo to suggest how the market might develop or what developments could be motivated by suitable flanking policies.

It is divided into **‘Settlement’ and property cogeneration (residential and CTS/non-residential buildings**, prepared by IFAM) and **industrial cogeneration** (prepared by IREES). Due to sectoral separation, there are few interfaces between the two areas investigated. Industrial undertakings currently purchase relatively little district heating, just as the district heating economy makes little use of industrial waste heat.

5.1 Potential determined for the private household and CTS sectors

A distinction is made when determining potential between

- the potential of ‘settlement cogeneration’, i.e. the use of cogeneration within the framework of district and local heating systems (referred to hereinafter as district heating cogeneration) and

- the potential of property cogeneration, i.e. use of cogeneration to supply individual properties or micro-clusters with no heating network.

These potentials overlap; as a rule, there are larger properties which represent more economic solutions in terms of property cogeneration and are, at the same time, in an economic district heating area (in which they may play an important role in terms of the economic viability of the area as a whole). As a rule, integration in a heating line-bound system is the most economically viable option; the potential is therefore considered mainly from that perspective, in order to determine the maximum potential; it is not an evaluation of ‘large-scale’ and ‘small-scale’ cogeneration. The method used to divide the two potential analyses can be found in Section 5.1.2.2.

Due to the enhanced technical complexity (compared to refrigeration production using electric compression chillers) and often higher costs, trigeneration is only used in a few niche applications and the production of refrigeration for the settlement cogeneration segment is practically negligible at present.

There are a few interesting applications; however, they go beyond the scope of this analysis. Moreover, they cannot be sensibly integrated into the processing method, which requires a spatial context. One example is computer centres, whose cooling requirement remains constant throughout the year. However, only approx. 350 of the 50 000 computer centres in Germany covered an area > 500 m² in 2013 (BI, 2014). The increased use of free cooling also allows more than 50 % of the heat generated to be discharged without the use of a chiller.
The number of full load hours of the chiller falls as a result, thereby reducing the suitability of trigeneration, which is why the economic potential of trigeneration is considered to be very low (TUB, 2012).

5.1.1 Potential of heat line-bound cogeneration

Heat line-bound settlement cogeneration potential is determined disregarding existing heat supply structures, as information on them cannot be obtained nationwide to the degree of detail required (specific network route with existing connections), as described more specifically below. Extrapolation based on individual examples is pointless, as there is too great a variety of supply situations in the towns. These cannot be generalised, not least due to the unknown hydraulic variance which existing network still offer in individual cases in terms of concentration and development. Even the capital costs which need to be imputed in order to determine distribution costs are unknown.

This results in a conservative estimate of cogeneration potential, as all networks must be considered as new networks to be laid.

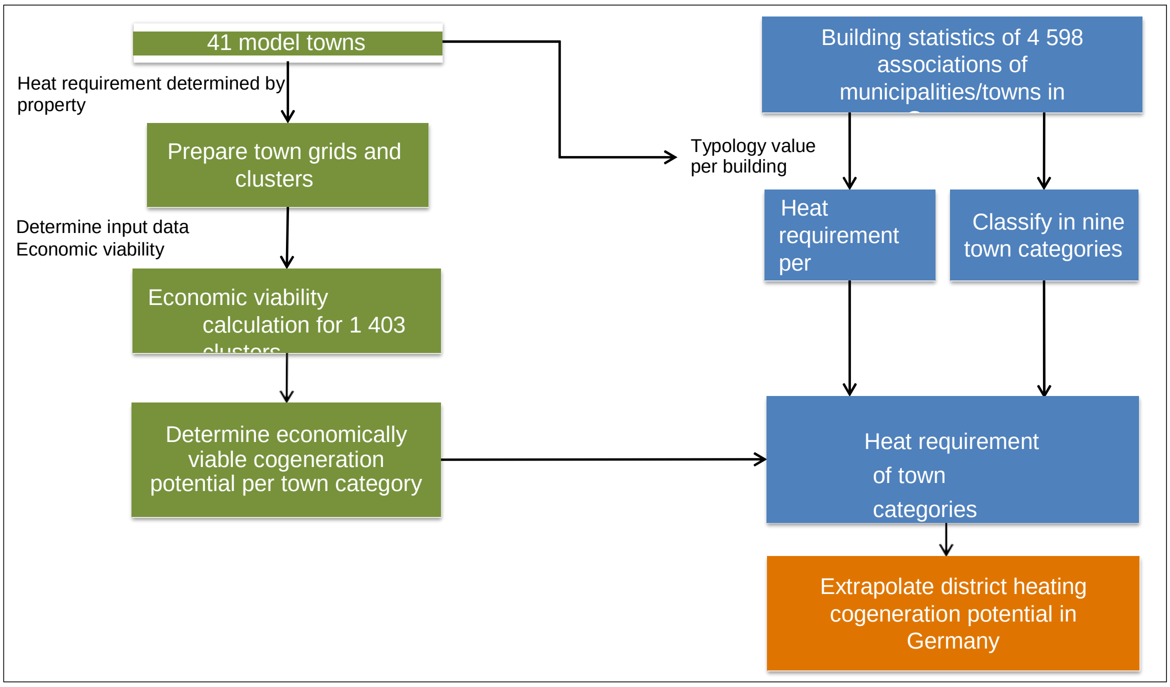
5.1.1.1 Basic method

The potential analysis for heat line-bound cogeneration can be divided into several work bundles:

- One work bundle concerns data compilation for all towns/associations of municipalities in Germany and their into town categories in terms whether the detailed information transfers well. Differences between towns in the old federal states and the new federal states must be taken into account.
- The **heat requirement** must be estimated (current) or extrapolated (future) for all towns/associations of municipalities in Germany.
- A large number of towns (**model towns**) was investigated in detail. It includes, above all, towns on which IFAM consumption data or comparable, high-resolution data (e.g. heating requirement by block) can be obtained and processed. That forms the basis for several detailed analyses. We mainly used 3-D laser scanning data, as well as information from oblique aerial photographs.
- These model towns were also **clustered** in order to take account of different settlement conditions. Numerical data on distribution lines and building connections were compiled on the same small scale.
- The town clusters were analysed in an **economic viability calculation** in order to determine the economic viability of district heating cogeneration. That gave the potential for cogeneration as a function of each scenario, subdivided by clusters.
- Finally, the information obtained from the clusters and model towns was used to **extrapolate** the settlement cogeneration potential for Germany as a whole.

The workflow is illustrated in Figure 16.

Figure 16: Flowchart for determining district heating cogeneration potential



Source: IFAM 2014

5.1.1.2 Formation of town categories

There are 4 598 towns/associations of municipalities in Germany. 780 associations of municipalities have a population of at least 20 000 inhabitants and offer good opportunities to make use of district heating. As the associations of municipalities differ enormously in terms of structure, categories are formed which are as homogenous as possible in terms of the size of their population and whether they are in an old or new federal state. The main structural basis is settlement density, which is determined based on living space (Stabu, 2014a) and number inhabitants per km² of settlement area (BBSR, 2013). Category VI is an exception. It includes towns in the periphery of a city as, due to the proximity to a regional metropolis (neighbouring city) differ in terms of settlement typology from similar sized towns (Category IV and V). Category IX includes all associations of municipalities with fewer than 20 000 inhabitants. The classification in categories is illustrated in Table 14.

Table 14: Definition of town categories

Category	Old federal states:	Number
I	Associations of municipalities with more than 350 000 inhabitants	14
II	Associations of municipalities with 150 001 to 350 000 inhabitants	30
III	Associations of municipalities with 80 001 to 150 000 inhabitants	48
IV	Associations of municipalities with 50 001 to 80 000 inhabitants	79
V	Associations of municipalities with 20 000 to 50 000 inhabitants	476
VI	Associations of municipalities with 20 000 to 80 000 inhabitants in the periphery of a city	22

	Total old federal states:	**669**
	New federal states:	
VII	Associations of municipalities with more than 80 000 inhabitants	14
VIII	Associations of municipalities with 20 000 to 80 000 inhabitants	97
	Total new federal states:	**111**
	Total in Germany:	**780**
	Other:	
IX	All associations of municipalities with fewer than 20 000 inhabitants	**3 818**

Source: IFAM 2014

5.1.1.3 Heat requirement of towns/associations of municipalities

The extrapolation is based on the tables die *Living space by year of construction and number of dwellings in building* (Stabu, 2014a) and *dwellings by year of construction* (Stabu, 2014b). The building age classes from official statistics are merged with the building age classes available to IFAM from the model towns. It includes the individual data merged at association of municipality level. The number of dwellings in one-family houses, two-family houses and apartment blocks is determined for each association of municipalities.

The mean size of a dwelling, subdivided by new and old federal states, building size and building age class is obtained from [Stabu, 2012]. Multiplying by the number of dwellings gives the living space at the level of associations of municipalities, subdivided into one-family houses, two-family houses and apartment blocks and by building age class.

For this structure of statistical data, area-specific heating requirement values must be deduced from the model towns. The typology values to be determined are based on more than a quarter of a million individual consumption data items provided to IFAM within the framework of various projects. In order to verify the procedure, the value determined from the statistical data is compared with that of the digital heat maps; only a minor correction to the initial typology values is necessary.

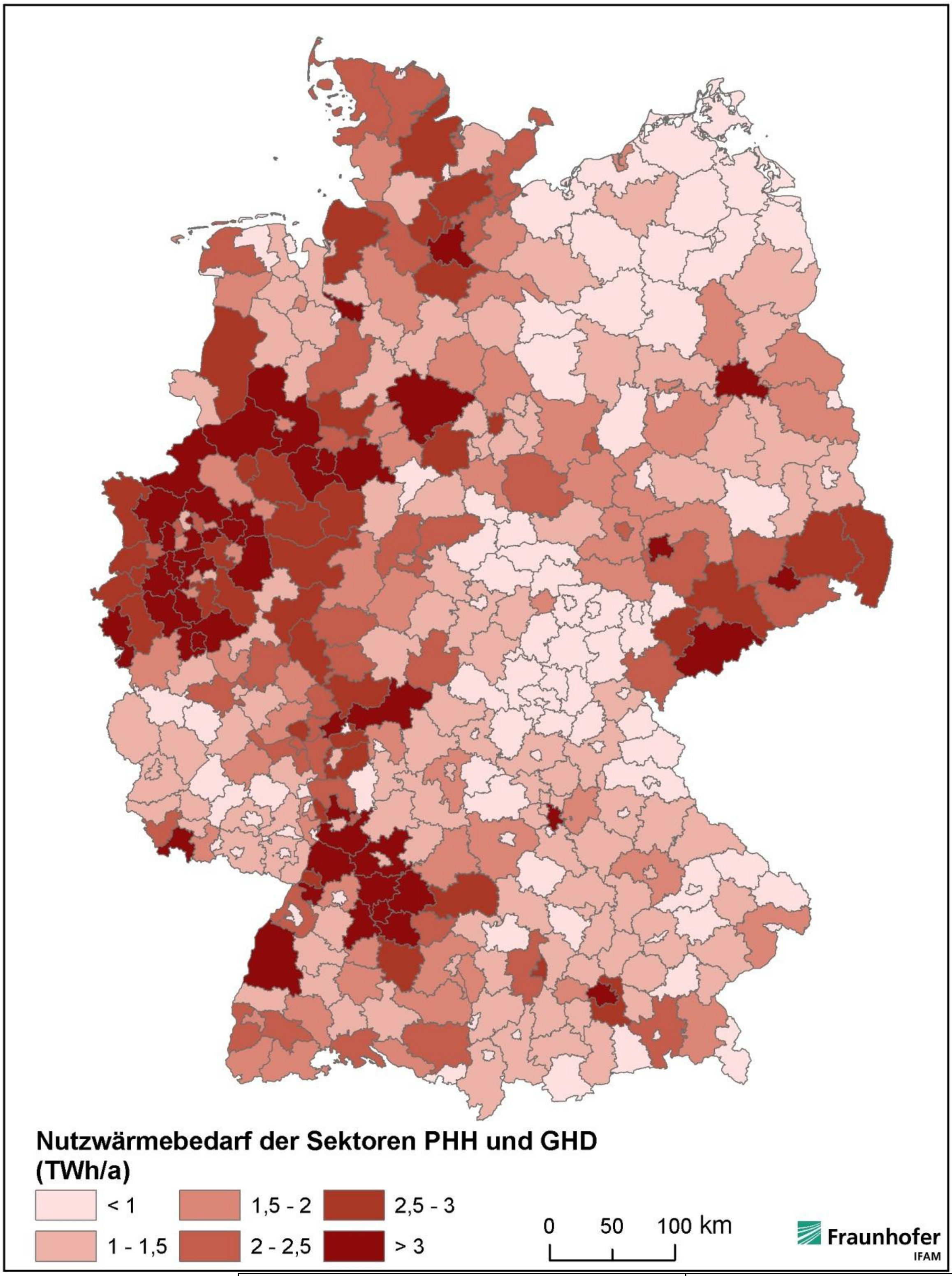
Overall, that gives a requirement of 538 TWh/a for Germany. That lies in the middle between two reference values used for plausibility testing. [AGFW, 2010] reports vale of 576 TWh/a for 2005/2006; what can only be a rough estimate for Germany based on final energy statistics (BMWi, 2014) gives a total of 506 TWh/a.

It is a known fact that determining the heat requirement of non-residential buildings is an very inexact science, as national statistics similar to those for residential buildings do not exist. That is due primarily to their considerable heterogeneity and the difficult in drawing a dividing line with industry. This fact was recently confirmed in a comprehensive ongoing IFAM research project (IFAM, 2014).

However, the model towns provide a relatively good basis due to the individual building solution and the integration of numerous real consumption values. The application of different methodical approaches based on the relative size of settlement areas and numbers of employees by industry illustrated an unsatisfactory correlation with the requirement values for the model towns obtained from consumption data in all cases. The most appropriate proved to be an extrapolation based on non-residential buildings using a reference factor to the heat requirement of residential buildings differentiated by town categories. Thus an overall requirement for the CTS sector of
224 TWh/a was calculated; this is sufficiently in line with what can only be a rough estimate based on final energy statistics for Germany (BMWi, 2014), which quotes 202 TWh/a.

Overall, the total useful heat requirement for the private household and CTS sectors in Germany was calculated to be 762 TWh/a. The spatial resolution by districts is illustrated in Figure 17.

Figure 17: Map of useful heat requirement in the private household and CTS sectors



	Useful heat requirements in the PHH and CTS sectors (TWh/a)

Source: IFAM 2014

5.1.1.4 Selection and source data for model towns

The model towns are selected first on the basis of availability, as very high resolution data are required (see Table 79 in the annex in Section 9.2.1). They can only be re-processed to a very limited extent within the framework of this potential study. The source data therefore are data from model towns available to IFAM from previous projects at individual building level. At the same time, it is important to use an adequate number of model towns in each category, in order to obtain representative averages. This increases in importance as the category increases in importance for the potential analysis, i.e. the larger the population. However, the clear increase in expenditure involved limits the scope of processing, i.e. the number of model towns.

In order to increase the number of model towns, specific heat atlases were requested for other towns, especially in the new federal states. In addition, the IFAM has carried out research on cogeneration investigations and potential analyses for all federal states. Moreover, in most cases, personal talks were held with the relevant departments (mostly ministries). There was few relevant data sources; often cogeneration options addressed together with energy concepts.
However, as the approaches and basic assumptions differed, this information was generally used for guidance only. The main focus when determining potential was therefore on the model towns.

Detailed data are available for model towns in the following federal states and they map an adequate range of typological conditions of settlements in Germany:

- North Rhine-Westphalia
- Lower Saxony
- Rhineland-Palatinate
- Brandenburg
- Consumer Protection
- Thuringia

A total of 41 model towns are available. Table 78 in the annex (Section 9.2.1) shows their classification in town categories.

In order to create as homogeneous a database as possible, the data on the model towns has to be processed and standardised. As a result, numerous attributes are available at the level of individual properties in each model town. They are listed and explained in greater detail in Table 79.

The overall heat requirement of the 41 model towns is based on 1.1 million buildings for which the aforementioned detailed data are available. As all real situational information can be taken into account, this is a sign, first, of the high standard of the database and, second, the improvement compared to the last national cogeneration potential study, in which the authors worked with representative settlement typologies.

5.1.1.5 Extrapolation of heat requirement

Changes to the heat requirement of residential buildings are determined by renovation effects and changes to total living space. Based on the values specified by Prognos (in keeping with the trend scenario in the energy reference prognosis), renovation is bringing about an annual reduction in the current decade of -0.50 % p.a. In coming decades the effect will gradually drop to -0.41 % p.a. The change for non-residential buildings is expected to be one-quarter lower.

The target scenario has slightly higher renovation effects than the trend scenario. In order to illustrate the difference, the sum of the space heat requirement and three-quarters of the hot water requirement (the last quarter is supplied by electricity or renewable energies and not substituted in the event of connection to district heating) is compared for the two scenarios.

Table 15: Heat requirement prognosis for private households in trend and target scenario

	2020	2030	2040
Trend scenario [PJ]	1 774	1 533	1 388
Target scenario [PJ]	1 762	1 475	1 231
Difference	0.7 %	3.8 %	7.9 %

Source: Prognos/EWI/GWS 2014, p. 261

As the table illustrates, the difference is very small in the next 10-15 years in particular; it is only after than that the two paths diverge more markedly. However, it is the first years that are important when calculating net present values; in terms of DMV, the difference between the two scenarios is a mere 3.4 %. This small difference illustrates the fact that the results in terms of potential would only change very slightly. Moreover, all input values exhibit bandwidths of reasonable assumptions which are certainly higher, i.e. slightly different assumptions would iron out the difference between the scenarios.

The change in living space in Germany as a whole are described under the basic conditions specified (see Table 16).

Table 16: Change in living space in Germany

	2011	2020	2030	2040	2050
Living space in km²	3 711	3 842	3 932	4 001	3 952

% change	-	3.5	2.4	1.8	-1.2

Source: Prognos 2014

In order to take account of regional effects, a differentiation is made based on the living space in associations of municipalities. The change in the number of dwellings from 2006 to 2011 (BBSR, 2014a) is well in line with the change in the demand for living space forecast for 2010 to 2025 (BBSR, 2011) and was therefore used as the basis for the spatial differentiation of the prognoses. As the data refer to land use regions, all associations of municipalities adopt the value of the next level (region) as the percentage change. This enables the living space per decade up to 2050 to be determined and summarised as an overall value for Germany. These values exhibit a slight deviation from the prescribed overall changes. The decade-related area change factors of the land use regions are then adjusted by that correction factor. A constant area is adopted as the value for non-residential buildings.

As these are applied to the model towns, economic viability is calculated taking individual account of the change in living space in those towns. The changes are modelled as structural adjustments to the inventory (gap closing/demolition), not as separate newbuild areas, as their location and size in a town cannot be predicted.

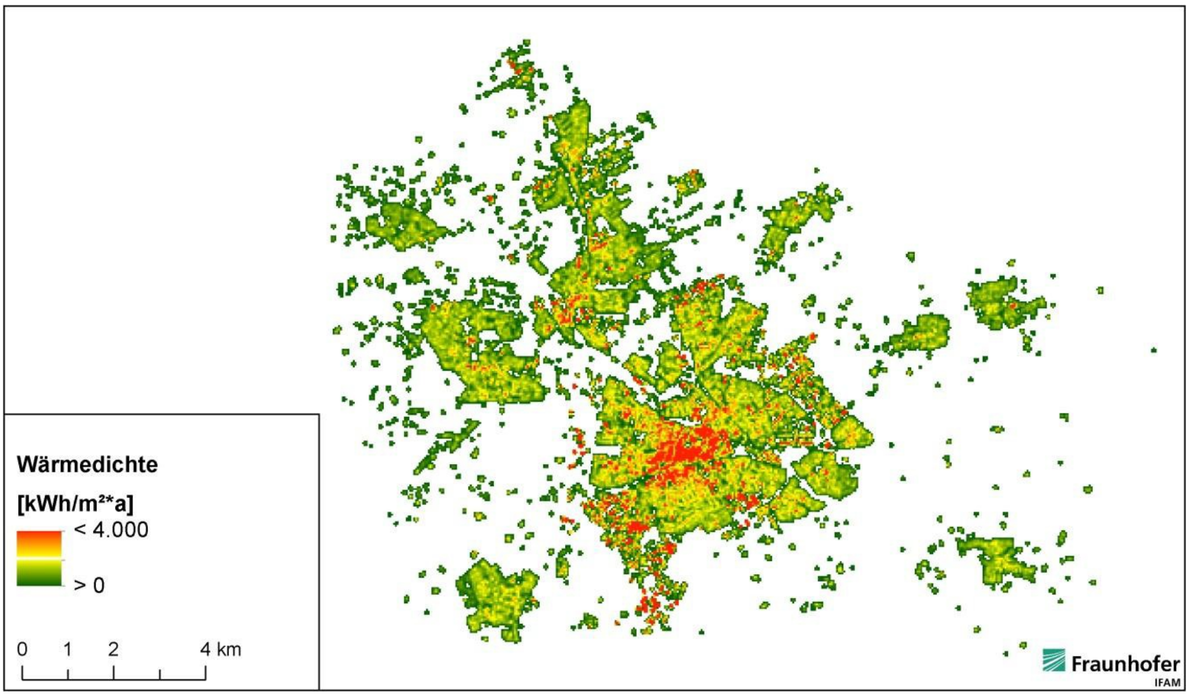
5.1.1.6 Clustering of model towns

The potential of line-bound cogeneration is extrapolated from the results determined for the model towns. One important exercise prior to calculating economic viability is clustering in the model towns. A cluster is a spatial unit whose economic viability is considered.

The method used to cluster towns was first used in [BEI,2011]. It was developed and improved in subsequent IFAM projects.

Clustering is based on a heat requirement map illustrating the specific heat densities (see Figure 18). The heat requirement of individual buildings is allocated to a cell in a 40 x 40 m grid. These cell values are then allocated pro rata to neighbouring cells; the proportion carried over declines as the distance declines. That illustration therefore focuses on the spatial correlation between buildings and their heat requirement rather than on individual buildings. The grid maps illustrate the heat requirement of individual settlement areas in high resolution.

Figure 18: Example of a grid map



	Heat density [kWh/m² x a]

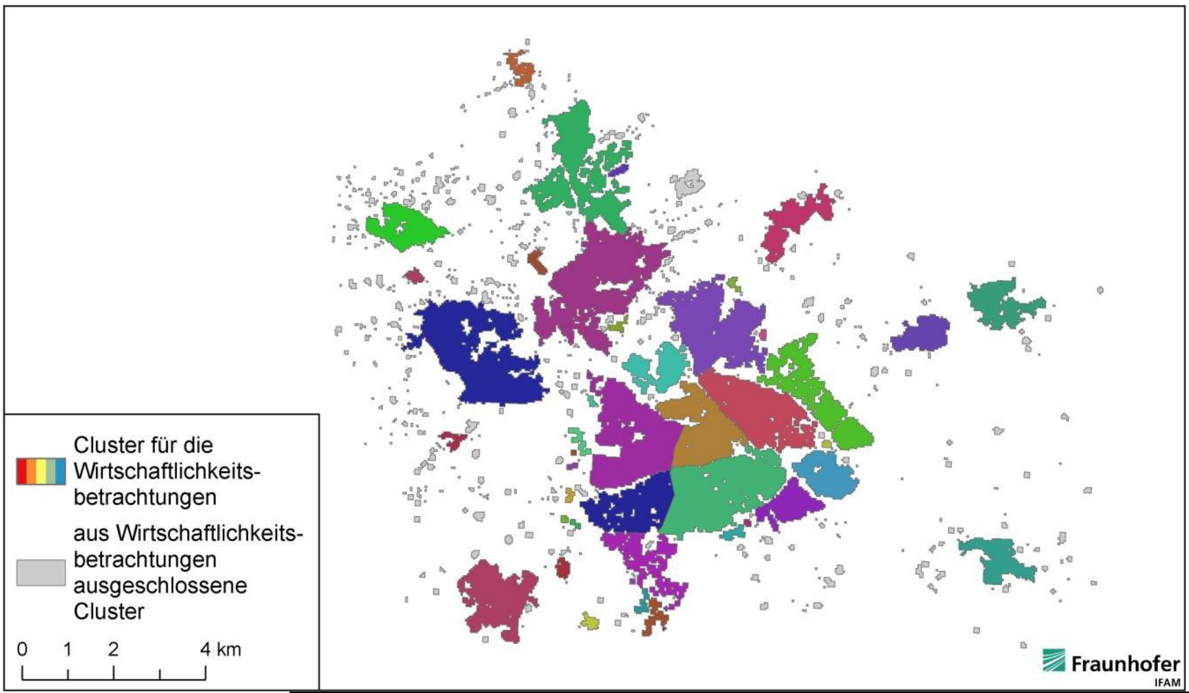
Source: IFAM 2014

These are used to form clusters of correlated areas whose cells lie above a certain threshold. In the town centre in particular, this method initially results in a very large cluster accounting for the major part of the town's heat requirement.

That large cluster is then divided manually, where possible using urban barriers, such as motorways or railway lines or settlement typology features (change to number of storeys). Following manual division, no cluster contains more than 15 % of the heat requirement of the town; as a rule it is less than 10 %. This ensures that no cluster has too great an influence on the overall result of subsequent economic viability analyses.
At the same time, clusters are excluded whose heat requirement lies below a certain threshold or which contain very few properties (see Figure 19). The properties in such clusters are included in the numerical data for the purpose of determining the potential of property cogeneration.

Figure 19: Clustering of towns

Clusters for economic viability analysis



Clusters excluded from economic viability analysis

Source: IFAM 2014

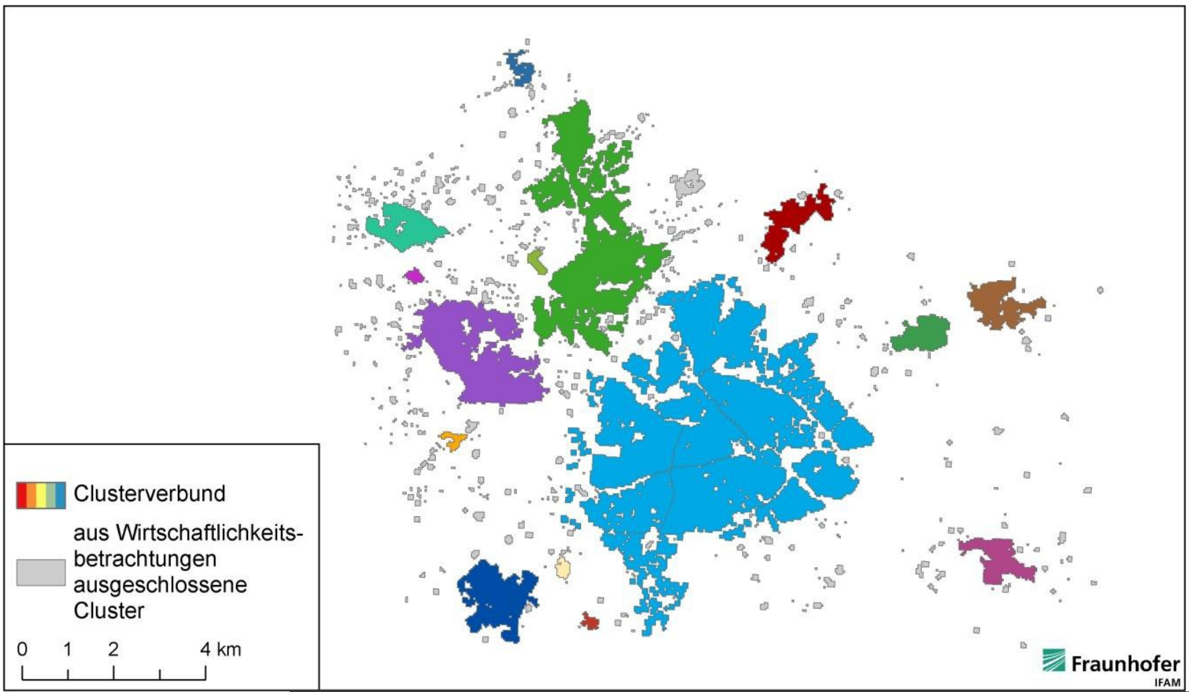
Clustering has been developed compared to previous IFAM studies by forming cluster networks (see Figure 20). These networks are marked by the fact that individual adjacent clusters contain a characteristic for their network. Clusters not in a network are ‘island clusters’. They are characterised by the fact that a heat line connection to a neighbouring cluster/network does not make economic sense. This means that the CHPP should be in or in direct proximity to that cluster, in order to service the demand for heat of the island cluster.

In cluster networks, the positioning of one or more CHPP is an monovariant that does not need to be determined, i.e. the demand for heat in the island cluster does not stand in a direct correlation to the sizing of the generation plant. This is explained in greater detail in the presentation of the methodology used for economic viability calculations in the following section. Economic viability is always checked individually for each cluster, regardless of whether or not it belongs to a cluster network.

The model towns have 1 403 clusters which are processed below (approximately 34 clusters per town).

Figure 20: Formation of cluster networks

Cluster network



Clusters excluded from economic viability analysis

Source: IFAM 2014

5.1.1.7 Scenarios investigated

The economic viability of local and district heating cogeneration depends primarily on the achievable connection rate. The higher the connection rate, the more economically viable the cogeneration solution compared to other alternatives. That is due to sinking specific heat production and distribution costs.

The aim of the potential analysis, from both the business (B) and the economic (E) perspective, is to determine the maximum economically viable potential. That is where cogeneration can supply the entire cluster. As in practice there is always a certain proportion of buildings which cannot connect to a district heating network for technical or customer-related reasons, these variations are calculated with a connection rate (CR in relation to heat requirements) of 90 % rather than 100 % (CR 90 B/CR 90 E). The distribution network is developed to 100 % of the maximum possible expansion in a cluster.

The connection rate forms the basis for the economic viability analyses of the clusters; it does *not* mean that 90 % of the entire town is also counted as connected district heating potential. Only the clusters which prove to be economically viable are counted in the potential (and then either 90 % or 45 % depending on the connection rate).

As such high connection rates are the exception in practice, two further scenarios with a connection rate reduced by half (45 %) are calculated for comparison purposes (CR 45 B/CR 45 E). This allows a degree of optimisation by not supplying unattractive street sections and connecting somewhat above-averagely large buildings; the effect is set at a very
moderate 10 %. The distribution network is thus only developed to 90 % (9/10) of the maximum possible expansion in a cluster. In order to connect 45 % of the heat requirement in that cluster, only 40.5 % (9/10) of all buildings need to be connected.

This means that the distribution network investment costs needed to get from the CR 45 scenario to the CR 90 scenario are equal to that 10 % optimisation effect alone. In the CR 45 scenario, the distribution network must be developed to the point at which it provides almost blanket coverage. Orders of magnitude of 350 km/600 km/1 100 km for Category III to I towns can be used as guidance in terms of the distribution network required for full development.

A reliable average current connection rate in Germany cannot be given, as the authors only have such sensitive data for a few supply areas and they cannot be published. Moreover, as a rule the connection rate is given for the sub-area within reach of the network rather than for the entire town.

5.1.1.8 Methodology used for economic viability calculation

The methodology used is based on work on the project to determine the cogeneration potential for the federal state of North Rhine-Westphalia [BEI, 2011], which was agreed following intensive discussion with representatives of energy supply companies and relevant associations. Certain details of it were varied and developed for this project.

All economic viability calculations are carried out on the heat side.

They are based on a dynamic process covering a period of 30 years (2014-2043). This follows from the correlation with the cost-benefit analysis and the equally long period of depreciation of the distribution network lines. In order to be able to calculate the numerous clusters and compare them properly with each other, the net present value (as real value in $€_{2013}$ net of VAT) needs to be correlated with the individual quantities of energy to give specific values (€/MWh), which are quoted as the discounted mean value (see Section 4.2). As this is an actuarial overall value for the period considered, the results cannot be compared directly to current values.

Economic viability has been calculated for each of the 1 403 clusters in accordance with the following condition (all figures in €/MWh):

Competitive district heating price

- Heat production costs

- Heat distribution costs

= x €/MWh

A cogeneration solution is economically viable if the total costs is less than revenue from customers (x > 0), i.e. allows a marketable (competitive) district heating price. The individual components are explained in greater detail in the following sections.

The result of these cluster calculations if, first, the total heat requirement in the economically viable clusters, expressed as the ratio of economically viable cogeneration to the overall heat requirement of a town/town category. That requirement is multiplied by the connection rate used in each scenario (see Section 4.1) to give the actual heat requirement that can be supplied by district heating cogeneration. That value can be used, taking account of network losses, the proportion delivered by peak load boilers and the cogeneration index, to calculate the quantities (heat and power) cogenerated.

The disadvantage of any such economic viability calculation is that it gives a ‘binary’ decision (economically viable/not economically viable). Clusters which (possibly only just) achieve a result of x > 0 are included in the potential found to be economically viable (with a full heat requirement value), whereas clusters which are only just below economic viability do not. However, two clusters which only differ very slightly in the range of x = 0 need to be considered as equivalent in terms of their economic viability.

IFAM therefore reports its results for settlement cogeneration in ‘economical viability’ increments of EUR 5/MWh. First, that presentation illustrates how robust the cogeneration potential is and what sub-quantities have clearly or only just exceeded the economic viability threshold. Second, this differentiation offers an additional advantage. It allows the effects of modified economic viability assumptions and basic conditions to be recognised, irrespective of where they are input into the calculation (a EUR 5/MWh higher price for heat has the same effect as production costs reduced by the same amount).

Distribution costs

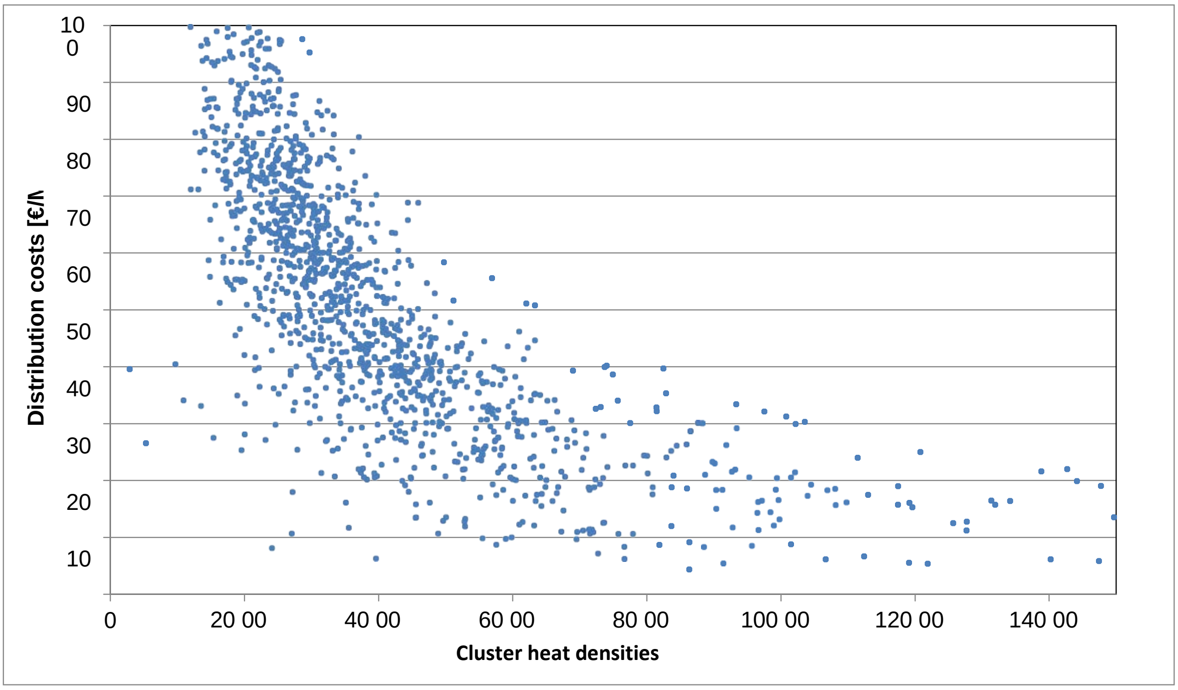
Distribution costs are divided in practice between the energy supply companies and customers such that the customer pays an additional connection cost or part payment on connection, which is differentiated by building transfer station, building connection line and distribution network. In practice the procedures have a certain bandwidth, depending on the individual price systems, market situations and usable grants (e.g. from the town). The specific breakdown is irrelevant to the potential calculations as, although each customer’s share reduces the distribution costs assumed for the supplier, competitive heat prices also fall accordingly.

Of the three aforementioned components, the costs of the building transfer station only depend on the performance of the buildings (i.e. they are independent of the heating network); the other two components follow individually from the specific network lengths, i.e. they cannot be given as uniform (representative) factors for a specific size of building. It therefore makes sense to allocate the distribution costs in the calculations: the customer pays 100 % of the costs of the building transfer station (which are included in competitive heat prices), but does not make any one-off payments towards the investment costs for the heat lines (which are therefore allocated individually to the buildings supplied in each cluster).

Table 80 in the annex (Section 9.2.1) lists the relevant cost estimates used to calculate distribution costs. They are based on information from undertakings and economic viability analyses prepared by IFAM for specific development scenarios in various projects.

Figure 21 illustrates the results for the distribution costs for the relevant section of all clusters, which are presented for the business variation with a connection rate of 90 % (see 5.1.1.7 for scenario definitions). It should be noted that most of the clusters have low heat densities and thus high distribution costs, which is why district heating cogeneration is not economically competitive in the following economic viability analyses. Table 17 lists the mean values for certain heat density classes.

Figure 21: Heat distribution costs from a 'business' perspective in scenario CR 90 B



Source: IFAM 2014

Table 17: Mean heat distribution costs from a 'business' perspective in scenario CR 90 B

Heat densities [MWh/km²]	Distribution costs [€/MWh]
< 40 000	70.1
40 000 - 60 000	36.0
60 000 - 80 000	25.0
80 000 - 100 000	20.3
> 100 000	16.3

Source: IFAM 2014

Competitive district heating price

The competitive district heating price is not differentiated by region for this investigation; it is a uniform value obtained from a full cost calculation in comparison to alternative, decentralised gas heating and determined for a relevant bandwidth of buildings with an annual heat requirement of 20-400 Gwh/a. The smaller the building, the higher the specific investments costs for heating, meaning that the capital costs account for a larger percentage than with larger buildings, for which the fuel costs increasingly dominate. Therefore the specific production costs are higher for smaller than for larger buildings. The costs of the building transfer stations paid by the customer are included.

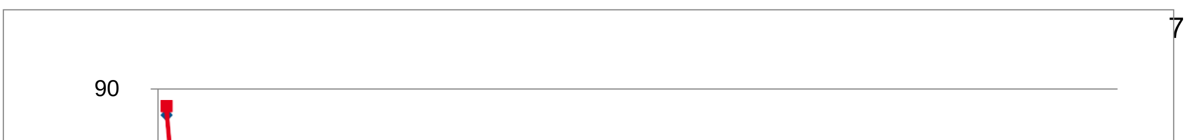
The distribution of the various connection cases can be read from the clusters as an entirety, for which a mean building heat requirement is determined for each building connection. The mean is weighted to obtain a uniform competitive price for heat which reflects the cost parity in respect of all buildings as an entirety. The values calculated are **89.5 €/MWh** from a **business** perspective and **79.4 €/MWh** from an **economic** perspective. The different results in a small measure only from the lower interest rate on capital costs; the impact of the energy tax is must more relevant.

Specific heat production costs

Specific heat production costs depend primarily on the CHPP used. The following plants are investigated for line-bound heat generation (see Table 9 for plant parameters): 50 kW_{el}, 500 kW_{el}, 2 MW_{el}, 10 MW_{el} for BHPP and 20 MW_{el}, 100 MW_{el}, 200 MW_{el} und 450 MW_{el} for G&S plants. For all plants 4 000 full load hours a year are taken into account and it is assumed that they supply 75 % of the annual heat.

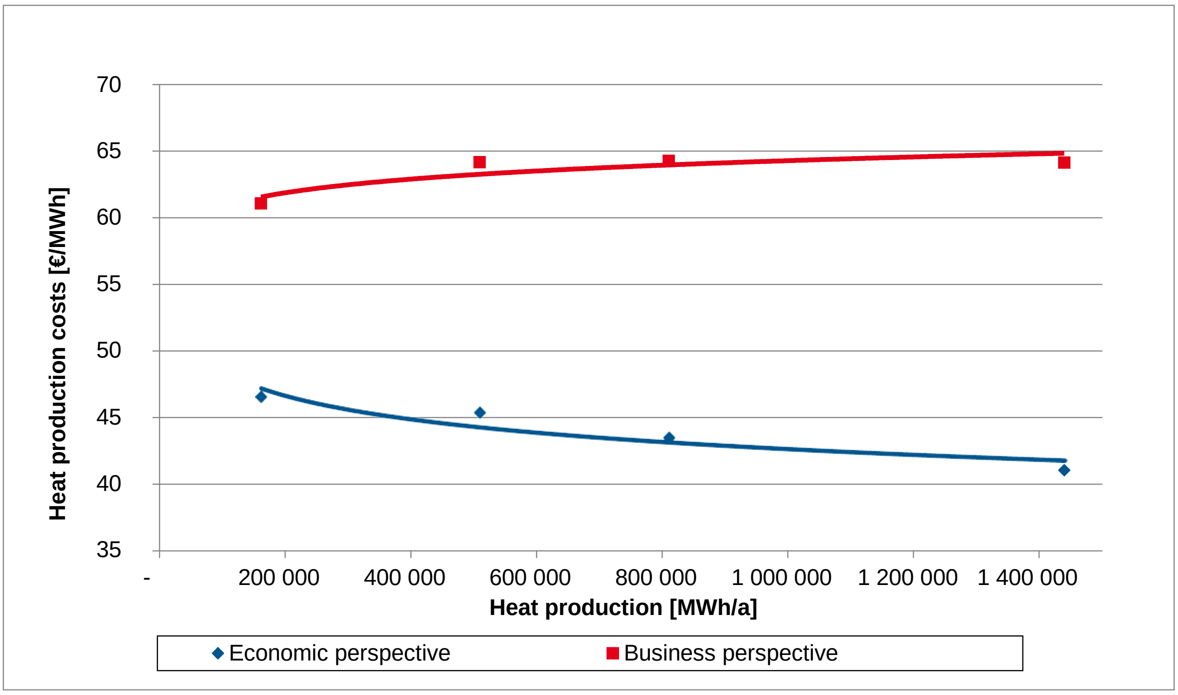
Figure 22 and Figure 23 illustrate the heat production costs (from an economic and a business perspective) for BHPP and G&S plants.

Figure 22: Heat production costs of BHPP with electrical capacity of at least 50 kW



Source: IFAM 2014

Figure23: Heat production costs of G&S plants



Source: IFAM 2014

The figures illustrate the following effects:

- The heat production costs of BHPP increase from both an economic and a business perspective in the lower capacity range for the smallest plants. In the upper capacity range, they fall from an economic perspective as the capacity increases; from a business perspective, however, they rise from 2 MW plants to 10 MW_{el} plants. That is due to participation in the ETS, in which all plants with a rated thermal input > 20 MW must participate. A correlation level for plants up to 10 MW is therefore pointless (illustrated by the broken line).

- The heat production costs of G&S plants fall from an economic perspective as the size of the plant increases; however, they rise from a business perspective. That is due to the fact that the cogeneration index rises as the size of the plant increases. As a result, the costs of fuel, maintenance and capital rise in relation to MWh heat, for which revenue from sales of electricity cannot overcompensate (as was usual in the past).

The difference between the two curves results in part from the effect already described in connection with competitive heat prices; however, it is a much more marked percentage effect due to the lower production cost level. Moreover, the capital cost portion is higher for CHPP; this is compounded by the effective interest spread on electricity sales which does not apply to gas-fired boilers. Overall, there are largish differences depending on the perspective (economic or business).

An alternative interpretation of the calculation from an economic perspective, taking account of the CO_2 levy, the cogeneration level and the RES levy[6], would not fundamentally change the ratios. The first two items offset each other and the RES levy is irrelevant as there is not private consumption of electricity.

The results raise the question as to what production costs need to be used in the calculations. As already explained in connection with clustering of model towns (see Section 5.1.1.6), sizing is obtained for 'island clusters' based on the requirement of the cluster and the associated costs from the correlation equations.

In cluster networks, there is a monovariant in terms of the plant. It follows from the results that, from a **business** perspective, larger BHPP and smaller CTS plants are the most economically viable; this is also currently a practice-oriented plant mix. As the values are very close (BHPP 55 €/MWh, G&S 61 €/MWh) a mean of **58 €/MWh** has been taken.

From an **economic** perspective, although the production costs fall slightly with larger capacity plants, an identical plant mix has been used so that the two perspectives can be compared better. The value of **44 €/MWh** used has been obtained from the individual values (BHPP 41 €/MWh, G&S 47 €/MWh).

Other assumptions and inputs

The other input values used for economic viability calculations are summarised in Table 18.

Table 18: Input data in economic viability calculation used to calculate district heating cogeneration potential

Input value	Unit	Value
Insurance and administration costs	% of investment	0.75
Administration and distribution costs	% of sales (in EUR)	5.00
Costs of crowding out natural gas (pro rata margin loss)	€/MWh	2.00

Source: IFAM 2014

5.1.1.9 Results in town categories

In the economic viability calculation, each cluster for which district heating cogeneration is economically viable is reported with the ratio between its heat requirement and the town's overall heat requirement. The total gives the proportion of the useful heat requirement that can be addressed by cogeneration in that scenario. The mean value of the results for the towns in one category gives the proportion for each town category. The results in the economic viability increments (Table 81 to Table 84 in the annex in Section 9.2.1) illustrate the degree to which the potential changes as a function of modified input values. In order to obtain a better comparison between the individual scenarios, the values in the economic viability increments refer uniformly to the demand for heat in the clusters, irrespective of the connection rate. The right column in these tables, which refers to the reference case (> 0 €/MWh), gives the proportion of the requirement connected via district heating cogeneration in the scenario described (appropriate requirement x connection rate).

The results are highly sensitive. Slight changes to input values cause a clear change in values: if the specific value is increased/reduced by just EUR 5/MWh, the mean changes (e.g. in scenario AG 90 B by approx. +/- 30 %). This proves that there are numerous cases at the limits of economic viability and minor changes on the market or to subsidies quickly cause a significant effect. From an economic perspective, the relative change is smaller due to the much higher overall level.

Table 19 summarises the results for the four scenarios. The left half of the tables gives the useful heat requirement which can be addressed in the economically viable clusters, *disregarding* the connection rate; the right half gives the requirement *with regard for* the connection rate. These quantities of heat are converted at the supply point to the quantities of cogenerated heat and cogenerated electricity produced when the district heating cogeneration potential for Germany is extrapolated.

Table 19: Results of scenarios for district heating cogeneration

Scenario	CR 90 B	CR 90 E	CR 45 B	CR 45 B	CR 90 B	CR 90 E	CR 45 B	CR 45 B
Town category	**Proportion of heat requirement in clusters suitable for**				**Cogeneration potential (useful heat requirement)**			
I	55.1 %	71.0 %	29.4 %	50.8 %	49.6 %	63.9 %	13.2 %	22.9 %
II	37.2 %	68.3 %	18.1 %	28.6 %	33.5 %	61.5 %	8.1 %	12.9 %
III	31.8 %	44.0 %	18.4 %	23.0 %	28.6 %	39.6 %	8.3 %	10.4 %
IV	30.7 %	46.4 %	13.1 %	22.2 %	27.6 %	41.7 %	5.9 %	10.0 %
V	15.2 %	27.2 %	6.4 %	8.6 %	13.7 %	24.5 %	2.9 %	3.9 %
VI	15.8 %	23.6 %	9.1 %	15.0 %	14.2 %	21.2 %	4.1 %	6.7 %
VII	52.6 %	66.6 %	14.7 %	31.1 %	47.3 %	59.9%	6.6 %	14.0 %
VIII	35.6 %	54.7 %	1.0 %	10.4 %	32.1 %	49.3 %	0.4 %	4.7 %
IX	3.6 %	13.2 %	1.3 %	1.3 %	3.2 %	11.8 %	0.6 %	0.6 %

CR: Connection rate E: economic calculation B: business calculation IFAM 2014

The results substantiate the anticipated graduation between the town categories. The largest ratios are in the cities, which is where most clusters with high heat densities or heat line densities are located and which are the most economically viable. The result for Category VII (> 80 000 inhabitants, NFS) reflects a different building structure (more large apartment blocks) compared to towns of similar size in the OFS.

The percentages in the CR 90 scenario are slightly below those obtained from the cogeneration potential analysis for North Rhine-Westphalia [BEI, 2011], although it defined town categories somewhat differently. One reason for that is the modified input values. The clear reduction in the spot electricity price, which has seriously depressed the economic viability of CHPP since that investigation, has been countered by the subsequent change to energy tax laws.

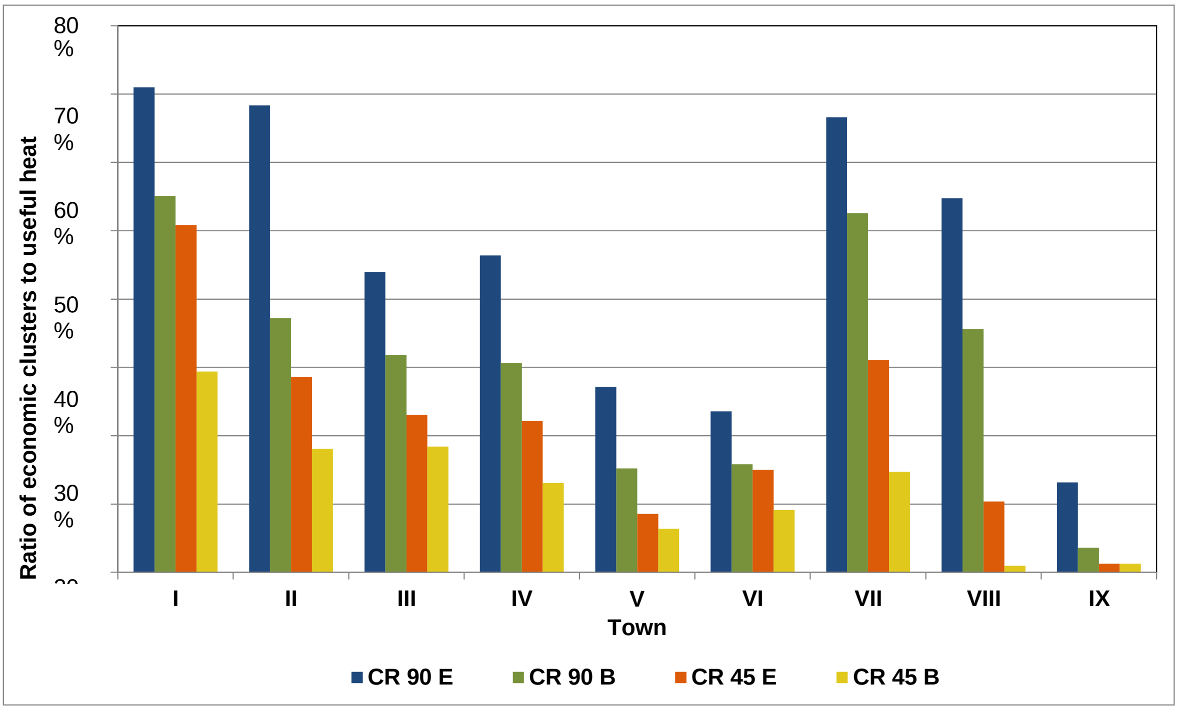
The results are much better from an economic perspective (scenario CR 90 E), although the ratios between the town categories are fundamentally the same. That is because, the improved production costs compared to the business perspective (14 €MWh for cluster networks) clearly outweighs the deterioration in competitive heat prices (10 €MWh for cluster networks).
This is compounded by reduced distribution costs (on average approx. 6/MWh), as the effects caused by the reduction in the interest rate from 3 % to 8 % have a much stronger impact than the abolition of the BAFA [Federal Office for Economic Affairs and Export Control] subsidy. The distribution costs are determined by the high capital cost quotas. Overall, this improves cogeneration by approx. 10 €/MWh.

In the scenarios with a connection rate of 45 %, there is a significant deterioration in the proportion of the demand for heat in clusters suitable for cogeneration. From a business perspective, that reduction (on average just over 50 %) is just as big as in the economic perspective. This proves the importance of the connection grade to the economic viability of line-bound cogeneration supply systems.

Based on the reduced connection rate, the actual quantities of heat connected fall to around one-quarter, compared to a supply with blanket coverage.

Figure 24 summarises the comparative results. It illustrates the heat requirement ratio in the economic clusters for the reference case (x > 0 €/MWh), i.e. the ratios *before* the connection rate is considered.

Figure 24: Results of scenarios compared



Source: IFAM 2014

5.1.1.10 Extrapolation of district heating cogeneration potential to Germany

These quantities of heat are multiplied by the economic proportions in the individual town categories to obtain the economically viable cogeneration potential in relation to the useful heat requirement (distribution network supply point). Figure 72 in the annex (in Section 9.2.1) illustrates the distribution of the useful heat requirement between individual town categories. A goo 60 % is accounted for by towns/associations of municipalities with more than 20 000 inhabitants.

The cogeneration potential on the **demand side** is given in Table 20. It relates to the current heat requirement.

Table 20: District heating cogeneration potential (demand side)

Perspective	Scenario	Unit	Value
business	CR 90 B	TWh/a	154
business	CR 45 B	TWh/a	35
economic	CR 90 E	TWh/a	249
economic	CR 45 E	TWh/a	56

Source: IFAM 2014

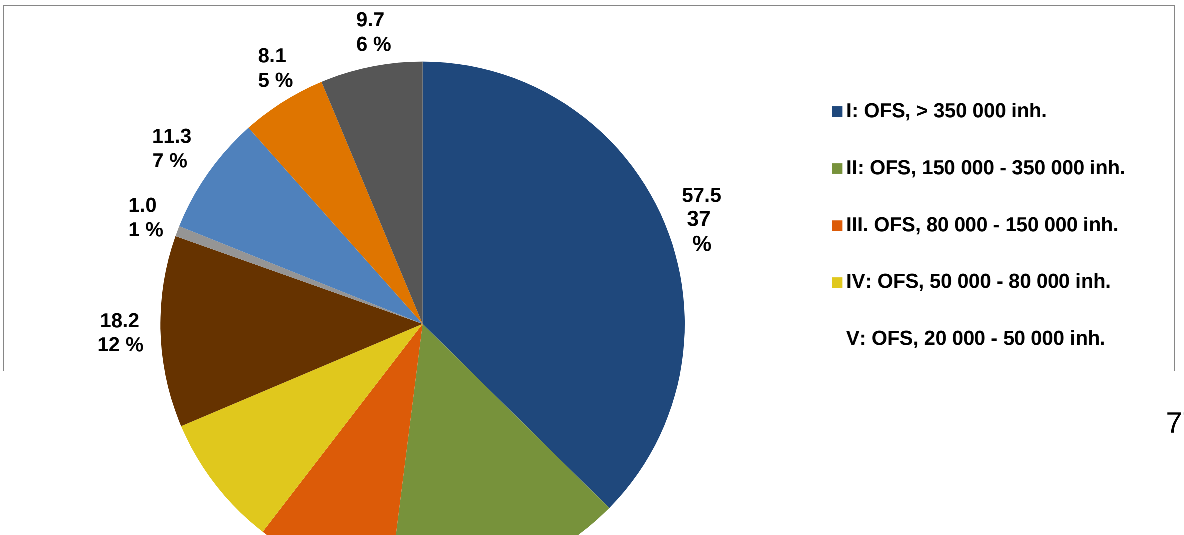
The **production side** potential that can be extrapolated from this is given in Table 21 and Table 22.

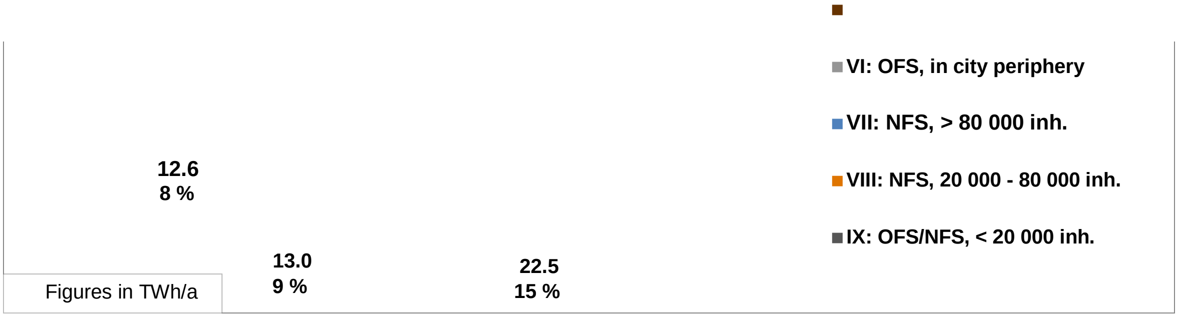
The values for the CR 45 scenarios are just under one-quarter of the values for the CR 90 scenarios. That is because there is on average about half the ratio of economically viable clusters and, in the clusters, exactly half the demand for heat in the clusters is connected to the network compared to the CR 90 scenario.

Figure 25 illustrates the distribution between town categories for the business perspective and Figure 26 illustrates the distribution for the economic perspective. In both cases, the variations with the 90 % connection rate area shown with the quantity of heat actually connected. The distributions cannot be compared, as the overall quantities differ.

The proportions in the individual categories only differ slightly from each other. The towns in the OFS with over 150 000 inhabitants account for approx. half the potential in each case (the proportion of useful heat requirement is just 24 %), underlining their huge importance to cogeneration potential/development of district heating cogeneration.

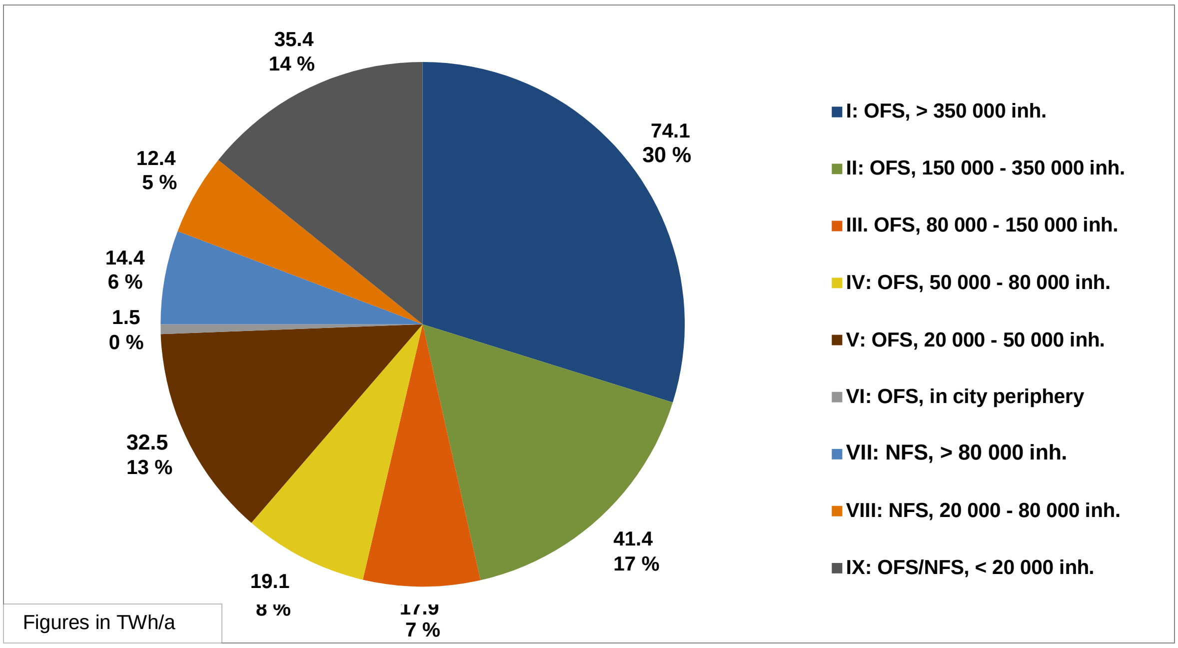
Figure 25: Breakdown of economically viable cogeneration potential by town categories in scenario CR 90 B in terms of useful heat requirement supplied





Source: IFAM 2014

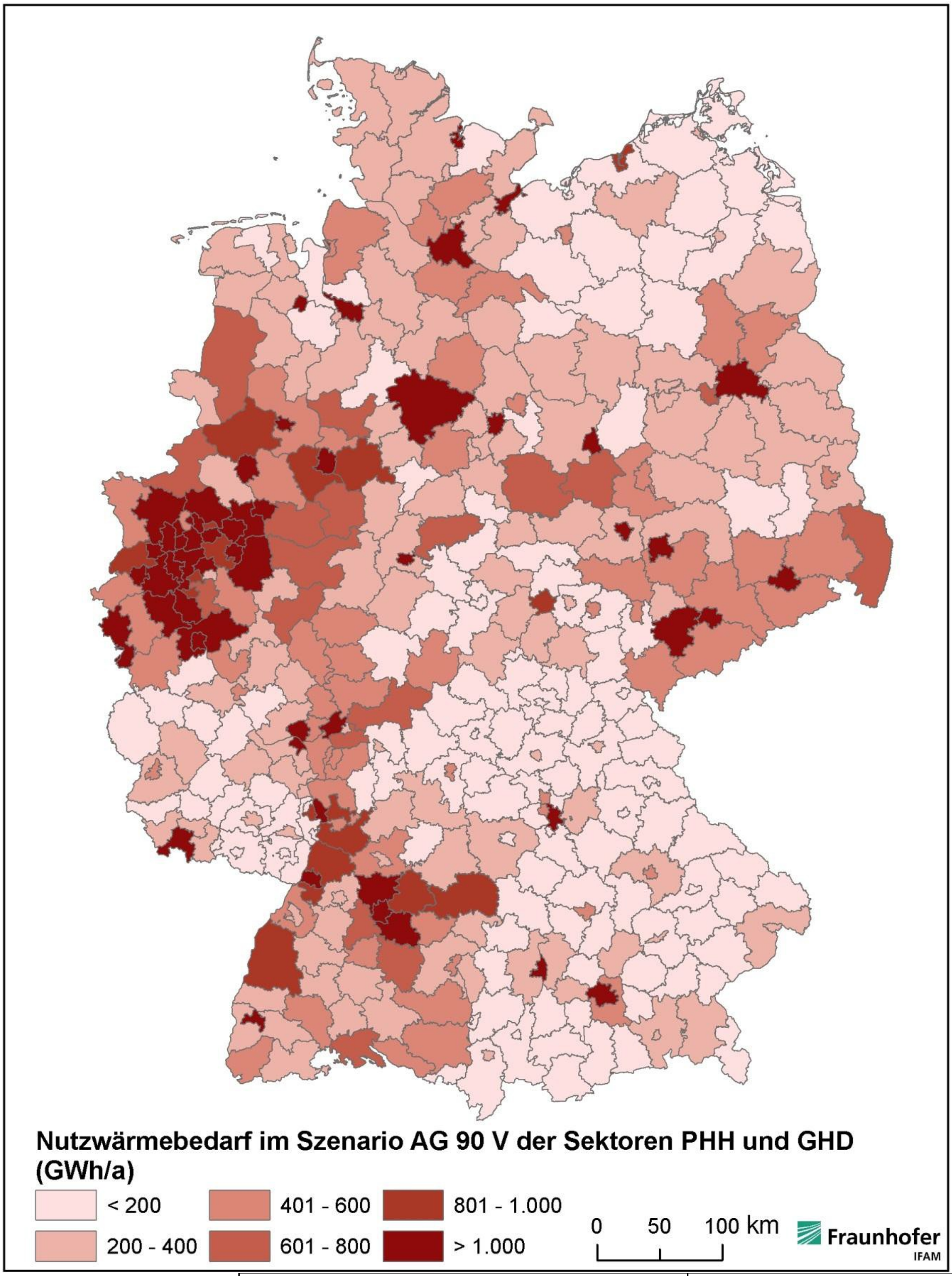
Figure 26: Breakdown of economically viable cogeneration potential by town categories in scenario CR 90 E in terms of useful heat requirement supplied



Source: IFAM 2014

Figure 27 illustrates the spatial distribution of potential for the economic variation. Unsurprisingly, there are considerable structural similarities with the useful heat requirement map for the sectors investigated (see Figure 17). There is no need for a business variation, as both maps are structurally similar once the class limits have been adjusted accordingly.

Figure 27: Map of economic district heating cogeneration potential from an economic perspective with a connection rate of 90 %



	Useful heat requirements in the PHH and CTS sectors in the CR 90 E scenario (TWh/a)

Source: IFAM 2014

The cogenerated quantities of this potential can be estimated taking account of network losses (10 %), the proportion of heat delivered to the network from peak load boilers (25 %) and a mean cogeneration index (0.88) (Table 21). The potentials from an economic perspective are around 1.6 times the potentials from a business perspective.

The results each indicate the maximum achievable quantities in a scenario. This ultimate development is achieved in the model calculation once decentralised existing heating has been replaced (just before 2030). Oil-fired and gas-fired boilers in particular will be crowded out of the market
.

Table 21: District heating cogeneration potential in Germany with connection rate of 90 %

Perspective	District heating cogeneration potential	Unit	Value
business	Cogenerated heat production	TWh/a	128
business	Cogenerated power production	TWh/a	113
economic	Cogenerated heat production	TWh/a	207
economic	Cogenerated power production	TWh/a	182

Source: IFAM 2014

Table 22 gives the corresponding figures for the scenarios with a connection rate of 45 %.

Table 22: District heating cogeneration potential in Germany with connection rate of 45 %

Perspective	District heating cogeneration potential	Unit	Valu
business	Cogenerated heat production	TWh/a	29
business	Cogenerated power production	TWh/a	25
economic	Cogenerated heat production	TWh/a	47
economic	Cogenerated power production	TWh/a	41

Source: IFAM 2014

5.1.1.11 Evaluation of the results for district heating cogeneration

Business perspective

The business potential of cogenerated electricity production with CR 90 (113 TWh/a) is at least twice the current electricity production for general supply (50 TWh/a, see Table 47); the heat production (128 TWh/a) is twice as high as the quantity of delivered heat (64 TWh/a) suggested for CHPP in the main AGFW report (does not cover the entire market).

With a practical connection rate of 45 %, only around half the current level is achieved. However, it should be noted that the potential calculations include the necessary networks at full cost and does not assume that distribution networks are wholly or partially depreciated. Grossly simplified, the result means that, without existing district heating structures, they can only be economically developed in the orders of magnitude that exist today with really high connection rates; with a connection rate in the order of magnitude of many existing district heating systems, this would not succeed.

Economic perspective

A comparison with the last national cogeneration potential study carried out for this sub-sector by Bremer Energie Institute [BEI, 2005] is only possible to a limited degree. Numerous basic conditions/input data have changed and different scenarios were considered. Also, there are significant differences in methodology; at that time, for example, taking account of the spatial location of clusters was as hard as taking account of the exact composition of buildings in the settlement correlations. The results presented in 2005 included the district heating inventory; the above tables do not.

In 2005, the potential for cogenerated heat production for district heating cogeneration was 199-233 TWh/a from an economic perspective. That order of magnitude has been confirmed by the value calculated here of 207 TWh/a.

The potential has been further evaluated together with the potential of property cogeneration in Section5.1.3.

5.1.2 Potential of property cogeneration

The potential for economically viable use of property cogeneration is determined based on the results of the model cost-benefit analysis and the settlement cogeneration potential analysis. As for line-bound cogeneration potential, the source data for the numerical data were the data on the 41 model towns for which IFAM has building-based information and data from federal statistics.

5.1.2.1 Basic method

The potential of property cogeneration, like the potential for line-bound cogeneration, is determined first based on the model towns for the town categories described previously and ultimately extrapolated at the level of associations of municipalities/towns (see diagram in Figure 16). The following operations were carried out in order to calculate national potential:

- The **numerical data** for economic viability testing of a property cogeneration solution were formed and prepared based on town clustering and the results of the district heating cogeneration potential.
- We defined eight **types of buildings/applications**. The types

of buildings are characterised by typical parameters in relation to their heat requirement. These types are defined taking account of the available differentiation of the database in the numerical data.

- A **full cost comparison** based on the results of the cost-benefit analysis is carried out in order to determine the **minimum heat requirement** which each type of building must have in order for supply via property cogeneration to be cheaper than supply using a gas-fired boiler. The calculations are carried out from both an economic and a business perspective.
- An **economic viability test** is carried out for each building from the numerical data from both an economic and a business perspective by comparing the heat requirement with the variable minimum heat requirement depending on the type of building.
- For the economic test, the size of the CHPP is calculated to give the cogeneration index. Thus the **quantities of cogenerated heat and power** can be determined for each property and then added together.
- These results are used to determine the potential of the nine **town categories** and, from that, to extrapolate the potential for property cogeneration at the level of associations of municipalities and towns for the whole of **Germany**.

5.1.2.2 Formation of numerical data and dividing line with district heating cogeneration potential

Care must be taken when establishing the numerical data and determining the potential at town category level and extrapolating for Germany based on that data to avoid double counting line-bound cogeneration and property cogeneration in the numerical data. Once the towns have been clustered, a residual small number of buildings remains in terms of the overall heat requirement which lie outside the clusters for which a district heating CHPP is then analysed. These are available without limitation for a property cogeneration option.

The district heating cogeneration analyses indicate if an economically viable solution presents itself, depending on the individual scenarios for each of the 1 403 clusters. For the two more important scenarios with a connection rate of 90 %, the clusters are determined in which this does not apply (952 from an economic perspective and 1 138 from a business perspective). These are primarily very small clusters in areas of less highly-developed areas, which explains the relatively high number. The very large number of all buildings in one of those clusters are filtered out of that database. That ultimately gives two lists for each model town with all buildings which also need to be tested for economically viable property cogeneration.

This approach ensures that the sub-potentials of district heating cogeneration and property cogeneration do not overlap and that duplication is precluded during when they are subsequently merged.

The data available at the level of individual buildings for the model towns must be prepared before they can be used for economic viability testing. The approach at individual property level is abolished in favour of address-based addition of individual attributes. The data at individual property level are obtained from basic geodata. However, a property does not always correspond to a building and, in particular, a heat supply network. The overall complex of all individual buildings at one address corresponds to the unit for which a heat supply is compared. An example is given in Figure 73 in the annex (Section 9.2.1). The buildings shown in yellow all have the same address. Without additional preparation, the economic viability of six individual properties would have been considered. In reality, although there are six individual properties or parts of the building, all the properties would most likely be supplied from one CHPP.

Aside from the heat requirement, the type of use, i.e. allocation to one of the eight types of buildings, is adjusted at shared address level. First, each individual property is allocated to one of the eight types of building based on type of use obtained from basic geodata. One address may house properties with different types of use. At shared address level, the type of building accounting for the largest proportion of heat is retained.

The proportion which is considered for supply by property cogeneration in the individual town categories increases in inverse proportion to the size of the town. That applies both to the basic stock of buildings which lie outside the potential for district heating and the cumulative quantities from the non-economically viable clusters. The building structure in larger towns tends to be more compact, meaning that line-bound cogeneration reaches a higher economically viable proportion and thus the quantities available from that perspective for supply via property generation declines accordingly.

5.1.2.3 Definition of types of buildings/applications

It is impossible within the framework of this investigation to test the economically viability of a property cogeneration solution at individual property level, given the enormous bandwidth of specific types of use resulting in individual heat requirement load duration curves. Therefore building uses are summarised under eight typical applications based on typical parameters.

Two considerations in particular are important when defining types of buildings: First, the definition must guarantee that the types of use summarised under one type of building exhibit similar heat requirement load duration curves. Second, it must be possible to classify by type of building via the numerical data on the model towns. Data are available at individual building level for the model towns from basic geodata (LoD1, ALK, ALKIS). Although the types of use recorded in basic geodata are comparable within towns, the property keys used differ partially from one town to another. The dividing line between residential buildings and CTS buildings is generally clearly visible from the data. Use of non-residential buildings is harder to differentiate. For certain types of use, such as schools or public buildings, differentiation is quite possible; however, approx. 80 % of non-residential buildings are allocated to large collective categories, such as ‘building for trade and industry in general’ (see IFAM, 2014).

The following seven types of buildings and an eighth collective category for all other buildings have been defined.

- single-family and two-family houses;
- apartment blocks;
- education and research institutions;
- healthcare facilities and residential homes;
- office-like facilities;
- indoor swimming pools;
- trade;
- other buildings.

The group of other buildings is so disparate that there are no representative annual load duration curves or set values.

Therefore, the estimates used for trade are applied as an approximation.

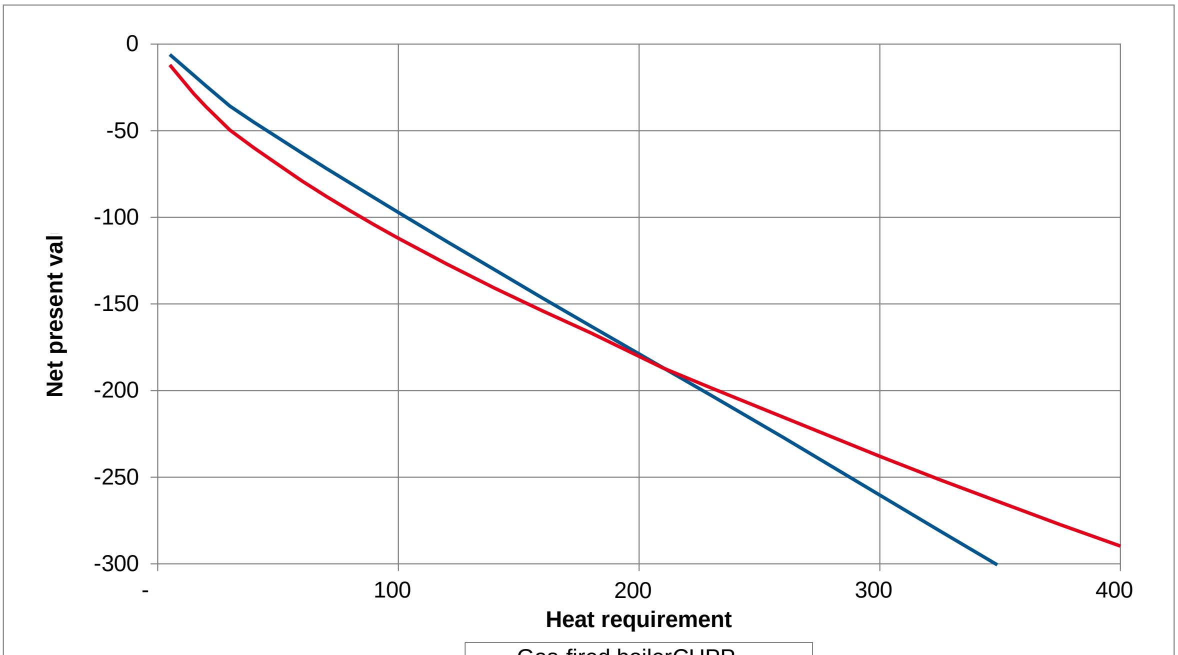
5.1.2.4 Determining the necessary heat requirement by type of building

Representative heat requirement load curves are taken from the BHKW-Plan design programme [BHKW, 2011] for the seven types of building defined. The resultant load duration curves and typical parameters for the design of CHPP are taken from the profiles in Figure 74 in the annex (Section 9.2.1).

When determining the thermal capacity of the CHPP, the objective is to achieve the maximum number of full load hours in order to improve the economic viability, on the one hand but, on the other hand, the proportion of the annual heat requirement covered by the CHPP should not be too small, in order to ensure that the proportion generated by the gas boiler is not too high. We used our own and our project partners’ empirical values for the rate of private use of electricity. For *trade* buildings, process heat was assumed to account for 25 % of the annual heat requirement for all buildings. It should be noted that the characteristics used are compromises which represent typical or mean values for all properties supplied under one type of building.

As with the cost-benefit analysis, a full cost approach was used to determine the necessary heat requirement of a building. The amount of individual cost items, such as the necessary investment in the CHPP, is determined with the help of the compensation functions described in Section 4.2.2. The net present value is calculated over a period of 30 years, depending on the heat requirement, for both the gas-fired boiler and the CHPP supply options. An example can be found in Figure 28 for the type 4 building *health facilities and residential homes* for the business perspective. The point of intersection of the two curves gives the quantity of heat above which the supply is more economically viable with a CHPP than a gas-fired boiler. The quantity of heat obtained for from both the economic for the business perspective is included in the profiles (Figure 74 in Section 9.2.1).

Figure 28: Heat requirement for type 4 building (health facilities and residential homes)



Source: IFAM 2014

For residential buildings, there are points of intersection for both types of building which are well above the realistic heat requirement of buildings of this type. Therefore the necessary quantities of heat in those cases are not included in the profiles, i.e. they have no economically viable potential.

The necessary heat requirement (i.e. the size of the property) is higher from an economic than a business perspective for all types of CTS buildings. That is due primarily to the varying level of savings made from private consumption of the electricity produced. Whereas electricity price components such as electricity tax can be saved from an economic perspective, that does not apply from a business perspective. A comparison between the limit values of the various types of buildings also illustrates that the rate of private use of electricity is crucial to the economic viability of a CHPP; the higher the rate of private use, the smaller the necessary minimum heat requirement of the building. Thus, as the calculations then illustrate, the 'success rate' is highest for type 4 buildings *healthcare facilities and residential homes*. In apartment blocks, the low rate (10 %) means conversely that the minimum requirement values are too high.

5.1.2.5 Economic viability analyses and potential in town categories

The economic viability analyses are based on the minimum quantity of heat that a shared address must have in order for a CHPP supply to be economically viable, determined for each type of building. That condition is checked for each shared address based on the quantity of heat and allocation to a type of building. The analysis is carried out for the following scenarios and numerical data:

- shared addresses outside a cluster for which line-bound cogeneration is a considered possible (business and economic perspective) form the 'foundation';
- shared addresses in clusters for which line-bound supply is not economically viable in the business scenario with a connection rate of 90 % (business scenario);
- shared addresses in clusters for which line-bound supply is not economically viable in the economic scenario with a connection rate of 90 % (economic scenario).

The economically viable quantities from the foundation and the scenario-dependent cluster quantities are added together. Thus the proportion of the quantity of heat for which a property cogeneration supply is economically viable is determined for each town category in the corresponding scenarios, measured against the quantity of heat for which property cogeneration is considered possible in the corresponding numerical data (Table 85 in the annex in Section 9.2.1). Category VIII includes just one model town for which the data needed for this operation did not have the necessary resolution. The potential cannot therefore be determined. Therefore the values of Category V were used to extrapolate the potential of Germany, as they compare well in terms of number of inhabitants with Category VIII towns.

The ratio of heat which can be economically supplied with property cogeneration to the overall heat requirement of the town category is then determined from both perspectives. The results can be found in

Table 23. The percentages from an economic perspective are much lower for two reasons: the 'success rate' of the partial quantities investigated is much lower (see Table 85), because the limit values of the necessary quantities of heat of the building rise markedly and the (cluster) quantities available are considerably smaller (see Figure 24).

Table 23: Ratio of quantities of heat available for economically viable property cogeneration by town category in relation to total heat requirement of a town in scenarios CR 90 B and CR 90 E

Town category	Business	Economic
I	3.4 %	0.8 %
II	3.3 %	0.7 %
III	5.2 %	0.6 %
IV	4.3 %	0.8 %
V	4.8 %	1.2 %
VI	5.6%	0.8 %
VII	4.7 %	1.3 %
VIII	4.8 %	1.2 %
IX	4.4 %	0.0 %

Source: IFAM 2014

5.1.2.6 Extrapolation to Germany

Finally, the potential determined at town category level is extrapolated for Germany for the CR 90 scenarios[7]. That extrapolation is based on the heat requirement values determined for line-bound cogeneration at the level of the associations of municipalities and towns. They are multiplied by the percentages for economically viable potential given in Table 23 to obtain the economically viable realisable potential for supply by property cogeneration for each association of municipalities. The results are given in Table 24.

The economically viable potential for property cogeneration in Germany, in relation to the useful heating requirement addressed is:

- 32.6 TWh/a from a business perspective;
- 4.3 TWh/a from an economic perspective.

The reasons why the potential is higher from a business than an economic perspective have already been explained in the section before Table 23.

Table 24: Economically viable property cogeneration potential available (useful heat requirement) in Germany in scenarios CR 90 B and CR 90 E

Town category	Business	Economic
	TWh/a	TWh/a
I	4.0	0.9
II	2.2	0.5
III	2.4	0.3
IV	1.9	0.3
V	6.4	1.6
VI	0.4	0.1
VII	p.m.	0.3
VIII	1.2	0.3
IX	13.0	0.0

Source: IFAM 2014

The quantities of cogenerated heat and power at individual building level are obtained by considering each economically viable case individually, the size of the CHPP and the association cogeneration index. They can be merged by category to give quantity-weighted mean values in relation to the demand for heat. These are applied to the values in Table 24 to obtain the quantities of cogenerated heat and power given in Table 25. The mean cogeneration index is 0.67 from a business perspective and 0.80 from an economic perspective.

Table 25: Property cogeneration potential in Germany in scenarios CR 90 B and CR 90 E

Perspective	Property cogeneration potential	Unit	Valu
business	Cogenerated heat production	TWh/a	20.9
business	Cogenerated power production	TWh/a	14.1
economic	Cogenerated heat production	TWh/a	3.3
economic	Cogenerated power production	TWh/a	2.7

Source: IFAM 2014

Calculating these potentials is a very time-consuming exercise; it has therefore been dispensed with for the CR 45 scenarios for determining maximum cogeneration potential in the private household and CTS sectors, as they are irrelevant. As Table 19 illustrates, the proportion of economically viable district heating cogeneration potential in the CR 45 scenarios falls to approximately half. Thus, the proportion of the quantity of heat available for property cogeneration is approximately twice as high.
Assuming that they have a similar composition of buildings as the clusters investigated for Table 25, the potential given here would approximately double.

5.1.2.7 Evaluation of the results for property cogeneration

The potential for property generation from an economic perspective is very small, due in part to the higher potential of district heating cogeneration. From a business perspective it is considerably higher. The potential is limited to non-residential buildings in both cases.

Table 62 gives a value for net cogenerated power production of 6 TWh for cogeneration below 1 MW_{el} for 2014 (whereby it should be noted that the quantity quoted for *general supply* includes additional small quantities from BHPP). A comparison between potentials proves that there are developable quantities from a business perspective.

The cogeneration potential reported is economically viable potential. However, in the property supply sector in general and the private household sector in particular, there are numerous decision-makers who have CHPP installed for various reasons, even if they are not economically viable based on the criteria adopted here (business rate of interest of 8 %). In numerous cases, proof that no loss will be incurred (0 % interest rate) suffices for a decision to go ahead; even moderate additional costs may be acceptable. This means that, in practice, CHPP are also erected outside the economically viable potential identified here.

In Germany, an average of 675 000 heat generators a year were renewed over the last ten years (2003 to 2013) (BDH, 2014); according to the annual accounts of the Germany heating industry a total of 686 500 heat generators were disposed of in 2013. With such high renewal figures, a cogeneration ratio in low single figures would result in tens of thousands of CHPP. This illustrates that there is additional potential here of a relevant order of magnitude with enormous opportunity for growth. However, one must always bear in mind that a large number of such small plants in the kW capacity range is needed in order to achieve the same effects in terms of quantities of cogenerated heat and power as a plant in a larger local/district heating system in the MW capacity range.

5.1.3 Conclusion: Potential in the private household and CTS sectors

The two sub-potentials (district heating and property cogeneration) are added together to give the overall potential in the private household and CTS sectors. The results for the scenarios with a connection rate of 90 % are summarised in Table 25, rounded to the nearest TWh/a. The results for the CR 45 scenarios are not listed at this point, as they were only roughly estimated for property cogeneration. Those results can be found in the relevant sections.

Table 26: Cogeneration potential in Germany in scenarios CR 90 B and CR 90 E

Generation potential	business	Percentage	economic	Percentage

	TWh/a	%	TWh/a	%
Cogenerated heat District heating	128	86	207	99
Cogenerated heat Property	21	14	3	1
Total cogenerated heat	**149**		**210**	
Cogenerated power District heat	113	89	182	98
Cogenerated power Property	14	11	3	2
Total cogenerated power	**127**		**185**	

Source: IFAM 2014

From an economic perspective, the potential for property cogeneration is irrelevant. That is due primarily to the higher proportion of economically viable district heat cogeneration clusters in the CR 90 scenarios, which leaves relatively small numbers of buildings for a decentralised cogeneration supply – a result of the priority given here to line-bound cogeneration supply which could also have been obtained differently.

From a business perspective, property cogeneration accounts for approx. 14 % of the overall potential (in relation to cogenerated heat production) and 11 % of cogenerated power production. The much worse economic viability of district heating cogeneration, on the one hand, and the much better economic viability of property cogeneration, on the other hand, compared to the economic calculation result overall in that distribution.

The evaluation of both sub-potentials (district heating cogeneration in Section 5.1.1.11, property cogeneration in Section 5.1.2.7) already includes a reference to the current state of development.

The potential described here obviously will not develop automatically simply because it is economical viable according to the basic assumptions made here. Different assumptions by developers may give very different results.
In addition, there are numerous other non-monetary obstacles.

For property cogeneration, the economic viability analyses are relative transparent, as they are based on known requirement profiles for individual properties, CHPP that can be sized to them and a fixed investment point.

The situation is very different in the case of district heating cogeneration potential. It must be developed over many years under unbundling conditions quantities in terms of requirements and customers which can only be estimated and which represent a very considerable economic risk if they are not achieved; this usually means that potential that is actually available is not realised. The displacement of gas customers must also be evaluated from a business perspective; customer loyalty plays an important part here.

Fundamentally, the objective is to achieve a supply which provides blanket cover with just one type of heat supply, as that allows costs to be optimised. At present, however, towns are still characterised to a large degree by parallel gas and district heating structures. This results in options on the customer side, but reduced capacity utilisation and thus higher costs for both network systems. A connection rate of 90 % generally depends on corresponding flanking policies in terms of basic conditions.

5.2 Potential of industrial cogeneration, including use of waste heat

The potential of industrial cogeneration was determined for two cases. First, a possible reference development was outlined (baseline scenario) and then a policy-driving variation was considered (see Section 5.2.4).

The baseline scenario essentially assumes that the basic conditions that apply today will continue to apply. It assumes that the political will to realise efficiency and climate protection gains through cogeneration will continue to apply and describes the possible development of industrial cogeneration in light of probable economic developments, taking account of foreseeable technological and structural changes in German industry.

Industrial cogeneration development could be speeded up over and above the baseline variation, if politicians and the economy so wanted for various energy- and climate-policy reasons.

Therefore an additional variation on the cogeneration development scenarios is outlined. That presumes the same economic development and the same energy efficiency and other technical developments addressed. It differs fundamentally in terms of the faster diffusion of CHPP in each branch of industry which could still clearly invest in CHPP, measured against the ratio of cogenerated heat to heat requirement <300°C. However, additional subsidy, information and further training programmes would be needed in order to realise this policy variation.

The method used to determine cogeneration potential is explained in detail in the annex to this report. Potential is determined based on:

- an analyse of heat requirement up to 300°C of the individual branches in 2012 which could theoretically be satisfied by cogenerated heat (see Sections 5.2.1 and 5.2.2);
- an estimate of its development over coming decades (see Section 5.2.3).

That is use as a basis for determining:

- first, the potential of cogenerated heat production in coming decades and

- with assumptions on the technology used and their specific power and heat production conditions (cogeneration index), the resultant cogenerated power production.

5.2.1 Heat requirement 2012 and its future development

For the base year (2012), cogenerated heat account for a large proportion of heat in the < 300°C range in the following branches (see Table 27 and Table 28):

- raw chemicals: 109 %; part of the heat generated by CHPP is channelled to external applications,
  e.g. neighbouring undertakings in other branches;
- cellulose and paper industry: 63 % and
- food industry: 37 %, due mainly to use of cogeneration in the sugar industry.

Overall in 2012, approx. 40 % of the heat requirement < 300°C in industry was supplied by cogenerated heat. It is not possible to give an exact figure, as statistics are not complied on BHPP under 1 MW and there is no way of establishing how many of the approx. 55 000 small BHPP served what proportion of the industrial heat requirement back in 2012.

Table 27: Distribution of heat requirement in 2012 by branch of industry and between heating and hot water with different process heat temperature levels required

Industrial sectors	**Space heating and hot water**	**Process heat**				
		< 100 °C	**100-200 °C**	**200-300 °C**	**300-500 °C**	**> 500 °C**
Food and tobacco	20 %	37 %	41 %	2 %	0 %	0 %
Automobile manufacture	33 %	26 %	23 %	0 %	0 %	18 %
Quarrying of stone and soil, other mining	4 %	84 %	5 %	5 %	1 %	0 %
Glass and ceramics	4 %	3 %	0 %	0 %	4 %	89 %
Raw chemicals	7 %	16 %	11 %	6 %	4 %	55 %
Rubber and plastic products	22 %	16 %	12 %	50 %	0 %	0 %
Machine engineering	33 %	20 %	16 %	0 %	0 %	31 %
Metal processing	17 %	0 %	1 %	1 %	0 %	81 %
Metal production	3 %	3 %	19 %	5 %	0 %	70 %
Non-ferrous metals/foundries	20 %	4 %	4 %	4 %	11 %	57 %
Paper industry	15 %	20 %	65 %	0 %	0 %	0 %
Other chemical industry	7 %	42 %	25 %	15 %	10 %	0 %
Rest of the economy	33 %	19 %	12 %	17 %	0 %	19 %

Processing of stone and soil	4 %	0 %	5 %	1 %	0 %	90 %

Source: IREES 2014; amended by Wagner 2002 & FfE 2002

Table 28: Energy consumption, fuel requirement for heat production < 300 °C and ratio of cogenerated power and heat to power requirement and heat < 300 °C by branch of industry in 2012

Industrial sector	energy source	Heat requirement in 2012 in TWh					Percentage in 2012 of	
		Heat/electricity requirement overall in 2012 in TWh1	Temperature range < 100 °C	Temperature range 100-200°C	Temperature range 200-300°C	Total < 300 °C	Cogenerated power production to power	Heat production to fuel consumption < 300 °C
Food and tobacco	Electricity	18.0	-				14 %	
	Fuels	35.9	13.1	14.8	0.8	28.7		37 %
Automobile manufacture	Electricity	17.9	-				2 %	
	Fuels	15.2	4.0	3.5	-	7.4		1 %
Quarrying of stone and soil, other mining	Electricity	1.8	-				14 %	
	Fuels	2.0	1.7	0.1	0.1	1.9		44 %
Glass and ceramics	Electricity	4.9	-				1 %	
	Fuels	14.4	0.5	-	-	0.5		3 %
Raw chemicals	Electricity	45.0	-				31 %	
	Fuels	84.7	13.7	9.1	5.4	28.1		109 %
Rubber and plastic products	Electricity	4.9	-				5 %	
	Fuels	16.0	2.5	2.0	7.9	12.4		3 %
Machine engineering	Electricity	11.3	-				1 %	
	Fuels	9,9	2.0	1.6	-	3.6		4 %
Metal processing	Electricity	15.8	-				n/a *	
	Fuels	14.4	0.4	1.5	1.5	3.4		n/a *
Metal production	Electricity	20.9	-				3 %	
	Fuels	120.9	0.6	1.6	0.4	2.6		7 %
Non-ferrous metals/foundries	Electricity	16.8	-				0 %	
	Fuels	13.7	0	0	0	0		0 %
Paper industry	Electricity	20.4	-				27 %	
	Fuels	37.8	7.4	24.6	-	32.0		63 %
Other chemical industry	Electricity	7.2	-				n/a *	
	Fuels	15.0	7.1	4.2	2.5	13,8		n/a *
Rest of the economy	Electricity	24.9	-				5 %	
	Fuels	26.5	4.9	3.1	4.6	12.5		38 %
Processing of stone and soil	Electricity	7.4	-				n/a *	
	Fuels	41.9	-	2.2	0.5	2.7		n/a *
Total industry	**Electricity**	**217**	**-**				**11 %**	
	Fuels	**452**	**58**	**68**	**24**	**150**		**40 %**

***:** Figures on this sector are confidential **1:** modified by AGEB

N.B. The figures on cogenerated power/heat production only include plants with output ≥ 1 MW.

Source: AGEB 2012; DESTATIS 2013 und 2014 a,b; VIK 2013; IREES 2014

The industry average ratio of cogenerated electricity to the overall electricity requirement (11 %) is understandably relatively small. As expected, the highest percentages are in the raw chemicals and paper industry (approx. 30 %).

Projected heat requirement of industry

Even the provisional result for 2012 illustrates that even the technical potential for cogeneration could at best be double the use of cogeneration, as the industrial heat requirement < 300°C might decline or stagnate in future if there are major efficiency improvements and slow growth in industry, especially as there is still considerable potential to use waste heat.

As explained previously in Section 4.3.4, heat-operated absorption refrigeration production (with a corresponding additional heat requirement) may increase the capacity utilisation of a CHPP and thus the rate of return on the overall operation of the plant in question. The foodstuffs industry, the chemical industry incl. the pharmaceutical industry, plastics processing and other branches of industry have very high refrigeration requirements between -15°C and +15°C (see annex for details). Clean room technology, which is also moving into the investment goods industry due to its high quality standards, is expected to increase the demand for refrigeration for air-conditioning.

The current power requirement for the production of industrial refrigeration between -15°C and +15°C corresponds in arithmetic terms to approx. 6 % of the industrial heat requirement < 300°C. This percentage suggests, although industrial refrigeration tends to improve the rate of return rather than act as a separate driving force for cogeneration.

Both efficiency gains and structure developments in industry, as well as technological changes must be taken into account when projecting the heat requirement < 300°C.

First, changes in the gross added value of industry and its branches from 2012 to 2050 were adopted from a previous Prognos projection of economic development in Germany (2014). There has been a marked interindustrial structural change towards less energy-intensive branches of industry (investment goods and consumer goods industries), which increase at an above-average rate in both projection periods (see Table 29).

Table 29: Industrial gross added value in Germany 2012 to 2050 (unit: billion €$_{2011}$)

Branch	2012	2020	2030	2040	2050	Annual growth rate	
						2012-2030	2012-2050
Quarrying of stone and soil and mining	1.6	1.3	1.3	1.3	1.4	-1.0 %	-0.3 %
Food and tobacco	31.2	31.8	33.9	36.1	38.4	0.5 %	0.5 %
Paper	9.7	9.8	10.1	10.3	10.4	0.2 %	0.2 %
Chemicals	48.7	56.8	66.5	74.6	82.8	1.7%	1.4 %
Raw chemicals	18.9	20.2	21.2	21.3	21.2	0.6 %	0.3 %
Other chemical industry	29.8	36.6	45.3	53.3	61.7	2.4 %	1.9 %
Rubber and plastic products	21.3	24.0	27.3	30.3	33.6	1.4 %	1.2 %
Glass, ceramics and bricks	5.4	5.2	5.2	5.4	5.7	-0.2 %	0.1 %
Cement, concrete, stone and minerals	6.1	5.9	6.2	6.7	7.2	0.1 %	0.5 %
Metal production and processing	20.6	20.9	21.7	22.5	23.4	0.3 %	0.3 %
Iron ore, steel and ferrous alloys	8.0	7.7	7.4	7.2	7.1	-0.5 %	-0.3 %

Processing of iron and steel, pipes	3.3	3.0	2.9	2.8	2.7	-0.7 %	-0.5 %
Non-ferrous metals/foundries	9.3	10.2	11.5	12.6	13.7	1.2 %	1.0 %
Metal products	36.9	39.2	42.1	44.5	47.2	0.7 %	0.7 %
Electrical engineering	78.8	88.8	101.4	112.8	124.9	1.4 %	1.2 %
Electrical appliances	41.3	49.2	58.0	65.4	73.0	1.9 %	1.5 %
Electrical equipment	37.5	39.6	43.4	47.4	52.0	0.8 %	0.9 %
Machine engineering	64.7	74.9	87.1	97.7	108.7	1.7%	1.4 %
Automobile manufacture	86.4	101.9	119.8	135.0	150.5	1.8 %	1.5 %
Motor vehicles and vehicle parts	72.3	82.8	96.1	107.8	120.0	1.6 %	1.3 %
Other vehicle manufacture	14.1	19.0	23.7	27.2	30.5	2.9 %	2.1 %
Rest of the economy	25.9	26.9	29.0	30.8	32.9	0.6 %	0.6 %
Total	**437**	**487**	**552**	**608**	**667**	**1.3 %**	**1.1 %**

Source: Prognos 2014

Furthermore, for very energy-intensive branches, we were able to use changes to physical production of important raw materials (e.g. oxygen and electric steel, primary and secondary aluminium, cement, paper etc.). These changes in production were multiplied by projected fuel and electricity intensities. Aside from technical developments such as progressive mechanisation and automation of industrial production (which is gradually decreasing in impact) or the increase in clean room technology etc., intrasectoral structural effects on less energy-intensive production structures due to higher standards, product support services in the investment and consumer goods industry and other additional added value effects were also taken into account

The most important effects on individual branches are reported below, in order to explain the projected change in fuel and heat requirements.

- In the *food and luxury food industry*, breweries stagnate and production declines in energy-intensive sugar production (due to the end of the EU sugar regulation in 2017). Ready meals with cold chains increase further. These intra-industrial structural changes reduce the specific energy requirement in addition to the efficiency gains.
- In *automobile manufacture*, although gross added value increases disproportionately, the number of vehicles manufactured stops increasing. This is again compounded by efficiency gains.
- In *glassware, ceramics and bricks*, production of hollow glass and consumer ceramics declines slightly, whereas production of more added value-intensive plate glass (triple glazing, PV modules) and special glass and ceramics and glass fibre continues to increase slightly. Aside from structural effects, additional efficiency potential is also realised. Overall, the added value of the sector remains constant.
- In the *raw chemicals* industry, energy-intensive electrolysis (e.g. of chlorine and fluorine) declines by volume and production of plastic precursors stagnates; this is also

reflected in stagnating gross added value from 2025, which only increases by 10 % from 2012 to 2025. Further slight efficiency gains are also realised.

- For *rubber and plastic products*, processing of plastics drives growth, whereas production of rubber products stagnates. In plastics processing, considerable efficiency gains are realised (especially in injection moulding: up to 50 %).
- In *machine engineering and metal processing* there is a marked increase in product support services and in the trend towards higher added value per machine and plant. From a technological perspective, it should be noted that automation continues to progress and clean room technology and dry manufacture spread. This covers efficiency gains on the power side, which become even more marked in terms of fuels (high efficiency potential, e.g. in powder coating, use of waste heat for warm baths).
- *Metal production* is very complex due to the primary and secondary routes for steel, aluminium and copper and thus changes to specific power and fuel requirements for these aggregated branches can only be plausibly understood based on our own model and a series of assumptions on physical production. Thus we assume that steel production will fall to 40 million t by 2020 and to 33 million t by 2050, with the ratio of electric steel rising continuously to 40 % in 2050. We assume that production of primary aluminium will fall by 20 % by 2050 and that secondary production will rise by 25 % compared to 2012.
- These structural changes result in a sharp decline in fuel and power, whereas the slight increase in gross added value of this sector will basically be achieved through higher grade steel and non-ferrous alloys. Energy efficiency gains tend to be small in this sector. However, the potential to use waste heat has not yet been taken into account.
- *Processing of non-ferrous metals and non-ferrous foundries* also moves towards higher-grade products (through to expanded metal products), whereas physical production only increases slightly. These structural effects are compounded by efficiency gains.
- While the gross added value of *paper and cardboard production* continues to increase slightly, production falls by a good 10 % by 2050 (conservative estimate). These structural effects are compounded by efficiency gains.
- The very dynamic *other chemicals*, especially pharmaceuticals and special chemicals, increase their gross added value on average twice as fast as the industry average. Value added effects are assumed to be especially high here. Moreover, there is considerable energy efficiency potential.

- In the *rest of industry* (mostly consumer good branches), the trend is likewise towards higher added value which is again compounded by existing efficiency potential.
- Although the *stone and soil industry* increases in terms of added value by a further 20 % by 2050; however, that is basically driven by product-support services (e.g. ready-mix concrete) or special products. We assume that energy-intensive cement production will decline in terms of volume. This is compounded by efficiency gains.

For industry as a whole, the annual changes in energy intensities peak at -0.9 %/a (electricity) and 1.3 %/a (fuel) in 2030.

5.2.2 Fuel and power consumption by branch and size of undertaking

In order to classify the frequency of various CHPP capacities, we had to break down the final energy requirement by size of undertaking. The power and fuel requirements of the individual branches of industry vary enormously depending on the size of the undertaking:

- In the raw materials industry and automobile industry, the large undertakings account for a large proportion of final energy consumption by the branch of industry in question – mostly over three-quarters of the final energy requirement of the branch of industry concerned (see Table 30).
- In the rest of industry, small and medium-sized undertakings account for a much higher proportion of final energy consumption by the branch of industry in question (e.g. small stone and soil quarrying companies: 51 % and metal processing: 30 %).

Table 30: Power and fuel requirement of industry in 2012, by branch of industry and three sizes of undertaking

Industrial sectors	Energy source	Energy requirement (in TWh) in 2012 for undertakings classed as:		
		Small	Mediu	Large
Food and tobacco	Electricity	2.9	6.2	8.9
	Fuels	4.4	16.7	18.8
Automobile manufacture	Electricity	0.3	1.7	15.9
	Fuels	0.3	1.6	14.9
Quarrying of stone and soil, other mining	Electricity	0.9	0.2	0.7
	Fuels	p.m.	0.5	0.5
Glass and ceramics	Electricity	0.4	1.9	2.5
	Fuels	0.9	6.0	10.9
Raw chemicals	Electricity	1.2	7.5	36.3
	Fuels	3.3	20.6	70.3
Rubber and plastic products	Electricity	0.8	1.9	2.2

	Fuels	2.4	7.1	8.3
Machine engineering	Electricity	1.5	3.8	6.0
	Fuels	1.2	3.1	6.8
Metal processing	Electricity	4.7	6.4	4.7
	Fuels	4.7	6.3	5.0
Metal production	Electricity	0.3	1.2	19.4
	Fuels	0.5	3.7	130.1
Non-ferrous metals/foundries	Electricity	0.8	5.1	10.9
	Fuels	0.7	3.7	10.8
Paper industry	Electricity	0.8	9.1	10.5
	Fuels	1.6	18.8	21.5
Other chemical industry	Electricity	3.5	2.0	1.7
	Fuels	5.5	5.5	7.6
Rest of the economy	Electricity	3.7	9,9	11.3
	Fuels	3.6	11.5	14.3
Processing of stone and soil	Electricity	2.1	2.6	2.7
	Fuels	6.6	17.2	22.7
Total industry	**Electricity**	**24**	**60**	**134**
	Fuels	**37**	**122**	**342**

Source: AGEB 2012; IREES 2014

This result alone illustrates that the future potential of cogeneration should tend to lie in investment and consumer goods industries and, in those industries, in smaller and medium-sized undertakings. This means that medium-sized and larger BHPP and smaller gas turbines plants will tend to be used.

Across the industry, 66 % of final energy (476 TWh) was allocated to large undertakings, 25 % (182 TWh) was allocated to medium-sized undertakings and the remaining 8.5 % (61 TWh) of final energy consumption was allocated to small undertakings.

5.2.3 Heat (< 300 °C) and cooling requirements in industry up to 2020 and prospects up to 2030 and 2050

Coupling the assumptions on gross added value and changes in the energy intensities of the branches of industry gives a differentiated picture (see Table 31):

- The heat requirement of industry as a whole < 300°C continues to rise from 2012 to 2030 by 0.9 % per annum. After 2035 it falls by approx. 1.5 % per annum so that the average increase for the period from 2012 to 2050 is just 0.3 % per annum. Demand elasticity therefore falls from 0.69 in the first period to below zero after 2030.
- Disproportionate increases in the heat requirement < 300°C are expected in other chemicals, especially pharmaceutical and fine chemicals (2.2 % and 1.3 % per annum) and in automobile manufacture and machine engineering and the foodstuffs industry (1.1 % and 0.4 % per annum).
- In some branches of industry, including stone and soil quarrying, the heat requirement < 300°C falls from now on.

The heat requirement in this temperature range in the glass and ceramics industry and in metal processing and metal production and the paper industry falls from 2020 onwards and the heat requirement of the raw chemicals industry and the ‘rest of industry’ falls from 2030 onwards.

This result means that in branches whose heat requirement < 300°C is stagnating or forecast to fall and which already have a high proportion of cogeneration (e.g. raw chemicals and paper), only re-investment in CHPP can be expected. Potential for large-scale development of cogeneration is expected mainly in those branches of industry in which the heat requirement < 300°C is high and rising and only a small proportion of cogeneration has been achieved to date.

Table 31: Heat requirement < 300°C for branches of the processing industry, 2012-2050 in GWh/a

Industrial sectors	**Heat requirement in TWh < 300 °C in GWh/a**					**Annual growth rate**	
	2012	**2020**	**2030**	**2040**	**2050**	**2012-2030**	**2012-2050**
Food and tobacco	25 862	31 200	31 300	31 200	30 100	1.1 %	0.4 %
Automobile manufacture	7 433	9 400	10 300	10 700	10 900	1.8 %	1.0 %
Quarrying of stone and soil, other mining	1 862	1 700	1 600	1 500	1 500	-0.8 %	-0.6 %
Glass and ceramics	464	500	450	400	400	-0.2 %	-0.4 %
Raw chemicals	28 149	32 900	33 400	32 300	30 400	1.0 %	0.2 %
Rubber and plastic products	12 414	15 000	16 300	16 900	17 100	1.5 %	0.8 %
Machine engineering	3 562	4 400	4 700	4.900	4.900	1.6 %	0.8 %
Metal processing	270	300	200	200	200	-1.7 %	-0.8 %
Metal production	32 866	34 600	32 200	30 300	29 000	-0.1 %	-0.3 %
Non-ferrous metals/foundries	1 645	2 000	2.100	2 200	2 200	1.4 %	0.8 %
Paper industry	32 017	35 100	34 900	34 300	33 000	0.5 %	0.1 %
Other chemical industry	13 778	17 800	20 300	21 600	22 100	2.2 %	1.3 %
Rest of the economy	12 543	14 300	14 600	14 500	14 100	0.8 %	0.3 %
Processing of stone and soil	2 705	2 900	2 900	3 000	3 000	0.4 %	0.3 %
Total industry	**175 568**	**202 100**	**205 250**	**204 000**	**198 900**	**0.9 %**	**0.3 %**

Source: AGEB 2012; IREES 2014

Qualitatively speaking, we can therefore conclude even at this stage that foodstuffs, rubber and plastics and other chemicals have the highest cogeneration potential. All three of these large branches also have increasing refrigeration requirements which, like their heat requirements, were determined based on changes in gross added value and cooling intensity (ratio of the energy requirement for cooling to gross added value) (see Table 32.

Table 32: Final energy requirement for refrigeration for branches of the processing industry, 2012-2050

Industrial sectors	Energy requirement for refrigeration in GWh/a					Annual growth rate	
	2012	2020	2030	2040	2050	2012-2030	2012-2050
Food and tobacco	5 528	5 900	6 500	7 000	7 500	0.9 %	0.8 %
Automobile manufacture	407	500	700	800	1 000	3.0%	2.3 %
Quarrying of stone and soil, other mining	-	-	-	-	-	-	-
Glass and ceramics	392	400	390	390	400	-0.1 %	0.1 %
Raw chemicals	8 898	9 500	10 200	9 900	9 200	0.7 %	0.1 %
Rubber and plastic products	726	800	1 000	1 200	1 300	1.8 %	1.6 %
Machine engineering	152	290	360	430	500	5.0%	3.2 %
Metal processing	-	-	-	-	-	-	-
Metal production	-	-	-	-	-	-	-
Non-ferrous metals/foundries	-	-	-	-	-	-	-
Paper industry	55	60	60	60	60	0.7 %	0.3 %
Other chemical industry	465	600	800	1 100	1 300	3.4 %	2.7 %
Rest of the economy	1 008	1 200	1 400	1 500	1 600	1.6 %	1.2 %
Processing of stone and soil	-	-	-	-	-	-	-
Total industry	**17 630**	**19 250**	**21 410**	**22 380**	**22 860**	**1.1 %**	**0.7 %**

Source: Our calculations IREES 2014

Overall, the cooling requirement of industry is disproportionately low compared to the increase in gross added value, as the considerable cooling requirement of the raw chemicals industry declines over the projection period.

5.2.4 Potential of cogeneration in industry up to 2020 and prospects up to 2030 and 2050 by branch and size of plant

The potential to further develop cogeneration in industry is described first in a guideline (baseline) scenario. This is expressly not a target for cogeneration development; it is an synopsis of the calculated rate of return on CHPP in industry (see Section 4.3) and anticipated changes to the heat requirement < 300°C of individual branches of industry (see Section 4.3), taking account of the quantities of heat already being produced by cogeneration (see Table 28). The baseline scenario essentially assumes that the basic conditions that apply today will continue to apply. It assumes that the political will to realise efficiency and climate protection gains through cogeneration will continue to apply and describes the possible development of industrial cogeneration in light of assumed economic developments, taking account of foreseeable technological and structural changes in German industry.

Industrial cogeneration development could be speeded up over and above the baseline variation, if politicians and the economy so wanted for various energy- and climate-policy reasons. Therefore an additional variation on the cogeneration development scenarios is outlined. That presumes the same economic development and the same energy efficiency and other technical developments addressed. It differs fundamentally in terms of the faster diffusion of CHPP in each branch of industry which could still clearly invest in CHPP, measured against the ratio of cogenerated heat to heat requirement <300°C. However, additional subsidy, information and further training programmes would be needed in order to realise this scenario variation.

Baseline scenario for development of industrial cogeneration

For the baseline scenario, assumptions had to be made for individual branches of industry, some of which also apply to the policy variation. They are as follows (see Table 33):

- in the raw chemicals industry, paper industry and stone and soil quarrying industry, no further increase in the proportion of cogenerated heat is expected (in some cases a reduction is expected), as these values are already very high. Basically re-investment is expected in these branches of industry in the future;
- in those branches for which no cogenerated heat production is reported in the cogeneration statistics for 2012, we have assumed small values from plants < 1MW. These values may be too small and may ultimately cause overly high growth rates between 2012 and 2030.

The difference in 2012 compared to official cogeneration statistics is based on confidentiality obligations imposed on statistics offices. Therefore overall cogeneration could not be actually allocated to the industrial sectors considered. However, the difference is reported for the record and extrapolated to 2050 using the average growth rate for industry as a whole (+1.3 % per annum (2030) or +0.7 % per annum (2050)).

Table 33: Potential for heat production by CHPP in the processing industry in Germany 2012-2050, baseline scenario

Industrial sectors	Cogenerated heat production potential, in GWh/a					Annual growth rate	
	2012	2020	2030	2040	2050	2012-2030	2012-2050
Food and tobacco	9 654	12 800	14 100	15 300	16 100	2.1 %	1.4 %
Automobile manufacture	78	470	1 000	1 400	1 600	15.1 %	8.3 %
Quarrying of stone and soil, other mining	815	800	800	800	800	-0.2 %	-0.1 %
Glass and ceramics	15	30	50	60	70	7.4 %	4.2%
Raw chemicals	30 746	33 900	34 100	32 600	30 400	0.6 %	0.0 %
Rubber and plastic products	403	1 100	2.100	3 000	3 400	9.7 %	5.8 %
Machine engineering	136	370	600	800	900	8.3 %	5.2 %
Metal processing1)	1	10	10	20	20	14.7%	8.7 %
Metal production	2 139	3 100	3 400	3 600	3 900	-2.6 %	1.6 %
Non-ferrous metals/foundries	242	330	430	490	500	3.2 %	2.0 %
Paper industry	20 177	22 500	22 700	22 700	21 800	0.7 %	0.2 %
Other chemicals1)	30	900	1.800	2.800	3 800	25.6 %	13.6 %
Rest of the economy	4 751	6 000	6 700	7 300	7 400	2.0 %	1.2 %
Processing of stone and soil1)	4	90	140	270	360	22.06 %	12.61 %
Total industry overall2)	**69 190**	**82 400**	**87 930**	**91 140**	**91 050**	**1.3 %**	**0.7 %**
Unreported difference compared to statistics3)	14 935	16 614	18 980	19 673	19 653	1.3 %	0.7 %

1) Values for baseline year 2012 estimated as statistics not reported.
2) Total of industrial sectors considered in detail.
3) Difference is due to official statistics subject to confidentiality requirements.

Source: DESTATIS 2013 and 2014 a, b; VIK 2013, in-house calculations IREES 2014

Overall in the baseline scenario heat produced by CHPP increases from 2012 to 2030 from 84.1 TWh to 107 TWh (or by 27 % or 1.3 % per annum). Growth is much slower after 2030 and heat generation stagnates from 2040 onwards. The change differ considerably from one branch to another due to their growth and current use of cogeneration.

- Even if the proportion of cogenerated heat is limited/declines, its value increases nonetheless by just under 3.4 TWh in the raw chemicals industry and by 2.5 TWh in the paper industry up to 2030. This development is due to further increases in production in both branches and is possibly an overly optimistic result in a reference development.
- There is a disproportionate increase with large potential in the use of cogeneration foodstuffs industry up to 2030 (+4.4 TWh), in the rest of the economy (+2.0 TWh), in other

chemicals (+1.8 TWh), in rubber and plastic products (+1.7 TWh) and in metal production (+1.2 TWh).

- There is also a disproportionately fast increase in the use of cogeneration up to 2030 in automobile manufacture (+0.9 TWh), in machine engineering (+0.5 TWh) and in a number of other branches with smaller potential.

Based on the cost-benefit analysis, we expect growth in CHPP to be driven essentially by BHPP of varying capacity and gas turbine plants (see Section 4.3). With an average power/heat generation ratio of 0.7 for these newbuild CHPP, electricity production grows by 2.4 % per annum up to 2030 to 43.2 TWh (see Table 34).

The approach used to determine the potential of cogeneration heat production was used for the potential of electricity production: the difference compared to the overall statistics was extrapolated based on the average growth rates of industry (+2.4 % per annum (2030) or +1.3 % per annum (2050)).

There is a marked increase between 2020 and 2030 with continuing capacity development driven by the (slight) growth in the raw chemicals industry and paper industry; at the same time, however, the other branches can increase their capacity perceptibly, as they currently have a small proportion of cogeneration relative to their heat requirement < 300°C. That also results in higher electricity production.

The increase in electricity production slows down after 2030 and stagnates in the period from 2040 to 2050.

Table 34: Potential for power production by CHPP in the processing industry in Germany 2012-2050, baseline scenario

Industrial sectors	**Cogenerated power production potential, in GWh/a**					**Annual growth rate**	
	2012	**2020**	**2030**	**2040**	**2050**	**2012-2030**	**2012-2050**
Food and tobacco	2 534	4 700	5 600	6 500	7 000	4.5 %	2.7 %
Automobile manufacture	403	700	1 000	1 300	1 500	5.4%	3.5 %
Quarrying of stone and soil, other mining	254	250	230	230	220	-0.6 %	-0.3 %
Glass and ceramics	36	50	60	70	80	3.2 %	2.0 %
Raw chemicals	14 012	16 200	16 400	15 300	13 800	0.9 %	0.0 %
Rubber and plastic products	225	700	1 400	2.100	2 300	10.8 %	6.4%
Machine engineering	75	240	380	500	600	9.4%	5.8 %

Metal processing 1)	0	10	10	10	20	18.8 %	10.6 %
Metal production	593	1 300	1 500	1 600	1.800	5.1 %	3.0%
Non-ferrous metals/foundries	25	90	150	190	220	10.7%	5.9 %
Paper industry	5 424	7 000	7 200	7 200	6 500	1.6 %	0.5 %
Other chemicals 1)	11	600	1 300	2 000	2 600	6.5%	15.6%
Rest of the economy	1 255	2.100	2 600	3 000	3 100	4.2%	2.4 %
Processing of stone and soil 1)	1	60	100	180	250	26.55 %	14.58 %
Total industry overall 2)	**24 848**	**34 000**	**37 930**	**40 180**	**39 990**	**2.4 %**	**1.3 %**
Unreported difference compared to statistics 3)	3 432	4 142	5 239	5 550	5 523	2.4 %	1.3 %

1) Values for baseline year 2012 estimated as statistics not reported.

2) Total of industrial sectors considered in detail.

3) Difference is due to official statistics subject to confidentiality requirements.

Source: DESTATIS 2013 and 2014 a, b; VIK 2013, in-house calculations IREES 2014

Policy variation of industrial cogeneration

With the exception of a few branches, the development of cogeneration would be faster than the baseline scenario outlined if existing obstacles in industry were reduced. This requires additional measures both by the federal government and federal states and by trade associations, focussing on information, further training, financing, contracting and risk hedging.

If the diffusion rates of cogeneration applications are increased in that sense up to 2050, the cogenerated heat and cogenerated power produced compared to the baseline scenario increase by 19 % and approx. 31 % over the years in question (see Table 35 and Table 36). Although this is not a very big additional contribution to the quantity of cogenerated electricity produced, every additional CHPP provides additional capacity to make power production more flexible.

- Particular large absolute potential for growth in cogenerated heat production up to 2030 compared to the baseline scenario is seen in the foodstuffs industry (+2.8 TWh), other chemicals (+1.9 TWh) and the rest of industry (+1.4 TWh) (see Table 35).
- Large growth rates in excess of 10 % per annum up to 2030 therefore tend to be in branches of industry of lesser importance to the energy economy: automobile manufacture, machine engineering, glass and ceramics and plastic products and, with growth rates of 6 % per annum, metal production and the non-ferrous metal industry.

Unlike wind energy, which has to be transported from generation points in the north of the country to consumption centres, the advantage of industrial cogeneration is that production and consumption are in close proximity. In that sense, increased development of cogeneration in those branches of industry which still have potential for use would help to reduce the size of long-distance power transmission capacities.

Table 35: Potential for heat production by CHPP in the processing industry in Germany 2012-2050, ambitious policy variation with enhanced proportion of cogenerated heat

Industrial sectors	Cogenerated heat production potential, in GWh/a					Annual growth rate	
	2012	2020	2030	2040	2050	2012-2030	2012-2050
Food and tobacco	9 654	15 300	16 900	18 400	19 300	3.2 %	1.8 %
Automobile manufacture	78	900	1.900	2.800	3 300	19.6%	10.3%
Quarrying of stone and soil, other mining	815	900	900	900	900	0.5 %	0.2 %
Glass and ceramics	15	50	90	100	120	10.2%	5.5 %
Raw chemicals	30 746	33 900	34 100	32 600	30 400	0.6 %	0.0 %
Rubber and plastic products	403	1.800	3 600	5 200	5 800	12.9%	7.3 %
Machine engineering	136	700	1 100	1 600	1.900	12.5 %	7.1%
Metal processing1)	1	20	20	40	50	19.2 %	10.7%
Metal production	2 139	5 600	6 100	6 500	7 000	6.0%	3.2 %
Non-ferrous metals/foundries	242	500	600	700	800	5.6%	3.1 %
Paper industry	20 177	22 500	22 700	22 700	21 800	0.7 %	0.2 %
Other chemicals1)	30	1.800	3 700	5 600	7 500	6.7%	15.6%
Rest of the economy	4 751	7 200	8 100	8 700	8 800	3.0%	1.6 %
Processing of stone and soil1)	4	150	260	480	700	26.11 %	14.37 %
Total industry overall2)	**69 190**	**91 320**	**100 070**	**106 320**	**108 370**	**2.1 %**	**1.2 %**
Unreported difference compared to statistics3)	14 935	17 597	21 600	22 949	23 392	2.1 %	1.2 %

1) Values for baseline year 2012 estimated as statistics not reported.
2) Total of industrial sectors considered in detail.
3) Difference is due to official statistics subject to confidentiality requirements.

Source: DESTATIS 2013 and 2014 a, b; VIK 2013, in-house calculations IREES 2014

Table 36: Potential for power production by CHPP in the processing industry in Germany 2012-2050, ambitious policy variation with enhanced proportion of cogenerated heat

Industrial sectors	Cogenerated power production potential, in GWh/a					Annual growth rate	
	2012	2020	2030	2040	2050	2012-2030	2012-2050
Food and tobacco	2 534	6 500	7 600	8 600	9 300	6.3 %	3.5 %
Automobile manufacture	403	1 000	1 700	2 300	2 600	8.4%	5.1 %
Quarrying of stone and soil, other mining	254	340	310	310	310	1.1 %	0.5 %
Glass and ceramics	36	60	90	90	110	5.0%	2.9 %
Raw chemicals	14 012	16 200	16 400	15 300	13 800	0.9 %	0.0 %
Rubber and plastic products	225	1 200	2 500	3 600	4 000	14.2 %	7.9 %
Machine engineering	75	500	800	1 100	1 300	13.8 %	7.8 %
Metal processing 1)	0	10	20	30	30	23.6%	12.7%
Metal production	593	3 000	3 300	3 700	4 000	10.1 %	5.2 %
Non-ferrous metals/foundries	25	200	300	360	400	14.9 %	7.6 %
Paper industry	5 424	7 000	7 200	7 200	6 500	1.6 %	0.5 %
Other chemicals 1)	11	1 200	2 500	3 900	5 300	-	17.7 %
Rest of the economy	1 255	3 000	3 600	4 000	4 100	6.0%	3.2 %
Processing of stone and soil 1)	1	110	180	330	460	-	16.38 %
Total industry overall 2)	**24 848**	**40 320**	**46 500**	**50 820**	**52 210**	**3.5 %**	**2.0 %**
Unreported difference compared to statistics 3)	3 432	4 534	6 422	7 019	7 211	3.5 %	2.0 %

1) Values for baseline year 2012 estimated as statistics not reported.

2) Total of industrial sectors considered in detail.

3) Difference is due to official statistics subject to confidentiality requirements.

Source: DESTATIS 2013 and 2014 a, b; VIK 2013, in-house calculations IREES 2014

Overall, the values of the policy variation illustrate that there is still good untapped potential for cogeneration that additional measures by the administration and self-help organisations would make accessible to the economy.

The extent to which this potential could be increased for cogenerated power by using waste heat in ORC plants is an unknown quantity due to their capital costs, which are still high. On the other hand, waste heat > 300°C could be used in-house and in neighbouring undertakings to produce heat <300°C and thus reduce potential use of cogeneration. This applies in particular to metal manufacture and the first processing stages for steel, iron and non-ferrous metals.

For that reason, Section 5.2.5 briefly discusses the question of heat recovery and use of waste heat.

5.2.5 Potential of industrial power production using waste heat

The use of waste heat from industrial processes to produce electricity is addressed here, as it is an additional approach to efficient energy use which, like cogeneration technology, is still under-used by a long chalk. The main reasons are indicated in Section 5.2.7.

On the other hand, it should be stressed here that many branches fail to make adequate use of more intensive heat recovery of waste heat at higher temperatures to service the heat requirement of lower working temperatures in the same or a neighbouring undertaking (using the Pinch Method), even though it would be cost-effective. If greater use were made of this potential to use heat, the potential to apply cogeneration would decline. In order to estimate this, the following were also considered.

5.2.6 Technically suitable waste heat potential of industry for power production in 2020 and prospects for 2030 and 2050

Although the question of usable waste heat potential for power production has been raised repeatedly for decades, there is no reliable information on its volume based on empirical data in Germany. Only a few projects using ORC technology or with spilling motors (for small quantities of waste heat) have been implemented in German industry.

IREES (2010) has made a conservative estimate for Germany based on a survey of Norwegian industry. The usable waste heat potential of Norwegian industry was established from questionnaires sent to undertakings in energy-intensive branches during the course of the ENOVA study (2009). The quantities of waste heat unused to date were established in relation to the final energy requirement of those undertakings and transferred to the corresponding branches of industry in Germany (see Table 37).

Table 37: Quantities of waste heat > 140°C possibly available for power production using ORC and other technologies in the processing industry

Description	Final energy	Ratio of waste heat > 140°C to final energy	Ratio of waste heat > 140°C to final energy
	TJ		TJ
Metal production	561 846	30 %	168 554
Raw chemicals	460 104	8 %	36 808
Paper industry	242 634		

Processing of stone and soil	221 802	40 %	88 721
Food and tobacco	204 328		
Rest of the economy	215 970		
Glass and ceramics	92 501	3 %	2 775
Metal processing	114 476	3 %	3 434
Non-ferrous metals/foundries	133 674	3 %	4 010
Automobile manufacture	131 117	3 %	3 993
Other chemical industry	91 138	3 %	2 734
Machine engineering	84 435	3 %	2 533
Rubber and plastic products	81 298	3 %	2 439
Quarrying of stone and soil, other mining	17 777		
	2 653 101		**316 001**

Sources: AGEB 2008, FH-ISI, ENOVA Spillvarme 2009

The factors from the Norwegian study were adopted for metal manufacture, raw chemicals and processing of stone and soil. The highest potential is expected here, as the quantities of waste heat > 140°C are approximately 295 PJ (approx. 82 TWh). For other branches assumed to have relevant waste heat potential, waste heat > 140°C was assumed across the board to be 3 % of the final energy requirement. That gave a further 20 PJ of waste heat > 140°C, which is possibly underestimated. Technologically speaking, these waste heat sources are mostly metallurgical processes or other high-temperature processes such as tempering, casting, firing or smelting.

Furthermore, no information is available as to how much of the overall 316 PJ (87 TWh) could cost-effectively be turned into power. It is hard to make an estimate as the waste heat > 140°C generated in numerous branches could also be used for the process heat requirement < 140°C, dubitably more cost-effectively than for power production. Evaluations in initial consultancy reports refer to 366 medium-sized undertakings where cost-effective projects to use waste heat have been identified which generate internal energy savings of 110 Gwh (or EUR 4 million in saved energy costs).

Assuming in light of the situation in terms of competition for use of waste heat that there is possibly cost-effective potential of 5 to 10 % of the waste heat potential > 140°C up to 2030, that 4.5 to 9 TWh of waste heat a year, with a moderate efficiency rating of ORC plants of 15 %, would give power production potential of 0.7 to 1.5 TWh a year. Measured against the potential for growth of cogeneration up to 2030, that is only 5 to 10 %; however, that power without CO_2 emissions is worth further consideration on the grounds of climate protection.

5.2.7 Obstacles to the use of waste heat in industry

The use of waste heat from industrial processes is contingent upon both a series of factors within the undertaking and in the energy economy.

Internal factors

- As a rule undertakings have no relevant data on energy flows (temperature level and mass flows) relevant to the use of waste heat. Thus, as a rule, they are also not considered as a potential investment.
- Most waste heat is generated simultaneously with the heat requirement; however, due to the long additional lines needed to transport heat in developed undertakings and the inert matter in waste heat media, the possibility of investment is disregarded.
- Finally, the question of the reliability of waste heat sinks over a depreciation period of 10 years also raises uncertainty. This applies in particular where waste heat is delivered to third parties without a clear investment commitment or if the buyer goes bankrupt or converts his process. Practicable contracts are needed in such cases.
- High search and investment costs (and high planning costs) due to a lack of knowledge cause reticence among undertakings, especially where such investments do not form part of their core business. Rates of return calculated solely on the basis of investment sums are therefore too optimistic.
- This is compounded by the usual practice of basing investment decisions solely on amortisation periods with short refinancing periods which, given the high capital costs involved, are illusory.
- At times, fears are also expressed as to the safety of the waste heat extraction process or the quality of the waste heat available. These fears are also expressed in particular during the technical installation/ refitting phase.

Circumstances in the energy economy and basic conditions

Site operators often also have an unconducive environment outside the business.

- There is no branch-based overview of cost-effective ways of using waste heat (including ORC applications) and potential waste heat customers in neighbouring undertakings.
- There are too few experienced consultant engineers due to the infrequency of such investments; higher consultancy and planning costs are the rule as solutions are bespoke.
- Manufacturers of ORC plants or other solutions for using waste heat have high canvassing and consultancy costs due to the lack of knowledge among undertakings and consultant engineers which, if they are to cover their costs, make their plants too expensive.

5.2.8 Conclusion: Potential in industry

Both scenarios considered (baseline case and policy variation) illustrate

- stagnation in the use of cogeneration in three industrial sectors (raw chemicals, stone/soil quarrying/other forms of mining and paper, peaking in part around 2020 to 2030) and
- a notable increase in the use of cogeneration in other sectors of the processing industry (food, investment goods, consumer goods and commodities).

It should be noted that, due to unavailable statistics, the analyses carried out here only cover just a good 82 % of cogenerated heat production and just under 88 % of cogenerated power production of industry in the base year (2012). In order to give the reader an estimate, the developments determined here were applied to the remaining plants not included Table 38 and Table 39.

In the group of industrial sectors with stagnating cogeneration, the heat production potential in the baseline scenario initially rises up to 2030 by a good 11 % (+0.6 % per annum) and then falls up to 2050 by approx. 8 % compared to the potential in 2030 (see Table 38). Overall, that gives a slight increase in cogeneration potential of 1.3 TWh heat (approx. 2 %) and 0.9 TWh electricity up to the end of the period considered.

By contrast, the sectors with rising cogeneration potential, taken overall, show an increase of 13 TWh heat (5.7 % per annum) up to 2030 or a good 20 TWh (3.6 % per annum) up to 2050 (see Table 38).

Table 38: Potential for heat and power production by CHPP in the processing industry in Germany 2012-2050, baseline scenario

Industrial sectors		Cogeneration potential, in GWh/a					Annual growth rate	
		2012	2020	2030	2040	2050	2012 - 2030	2012 - 2050
Heat	Industrial sectors with stagnating cogeneration[1]	51 738	57 200	57 600	56 100	53 000	0.6 %	0.1 %
	Industrial sectors with increasing cogeneration[2]	17 452	25 200	30 330	35 040	38 050	3.1 %	2.1 %
	Industry overall[3]	**69 190**	**82 400**	**87 930**	**91 140**	**91 050**	**1.3 %**	**0.7 %**
	Unreported differences compared to statistics[4]	14 935	16 614	18 980	19 673	19 653		
	Total potential of industry[5]	**84 125**	**99 014**	**106 910**	**110 813**	**110 703**		
Electricity	Industrial sectors with stagnating cogeneration[1]	19 690	23 450	23 830	22 730	20 520	1.1 %	0.1 %
	Industrial sectors with increasing cogeneration[2]	5 158	10 550	14 100	17 450	19 470	5.7 %	3.6 %
	Industry overall[3]	**24 848**	**34 000**	**37 930**	**40 180**	**39 990**	**2.4 %**	**1.3 %**
	Unreported differences compared to statistics[4]	3 432	4 142	5 239	5 550	5 523		
	Total potential of industry[5]	**28 280**	**38 142**	**43 169**	**45 730**	**45 513**		

1) Raw chemicals, stone/soil quarrying/other forms of mining and paper

2) Food and tobacco, automobile manufacture, glass and ceramics, rubber and plastic goods, machine engineering, metalworking, metal production, NF metals and foundries, other chemical industry, other branches of the economic and processing of stone and soil.

3) Total for industrial sectors considered in detail, excluding unreported differences compared to statistics

4) Difference is due to official statistics subject to confidentiality requirements.

5) Total for industry as a whole with unreported differences compared to statistics

Source: DESTATIS 2013 and 2014 a, b; VIK 2014, in-house calculations IREES 2014

Overall for industry (including capacity not allocated to branches) in 2050 (see Table 38 and Table 39),

- there is heat potential that could potentially be produced by CHPP of approx. 110 TWh (+30 % compared to 2012) in the baseline scenario and
- slightly higher heat potential in the policy variation of 131 TWh (+56 % compared to 2012). This means that much more political effort is needed to realise that potential.

On the power side, the growth in cogeneration due to the better cogeneration index of add-on plants is notably higher. Overall, it should be noted that the growth in CHPP in industry clearly slows down between 2030 and 2040 and

- stagnates after 2040, i.e. the negative growth of CHPP in branches which currently have a high proportion of CHPP is compensated by the increase in CHPP in branches with greater potential for growth in the decade from 2040 to 2050.

Table 39: Potential for heat and power production by CHPP in the processing industry in Germany 2012-2050, ambitious policy variation

Industrial sectors		**Cogeneration potential, in GWh/a**					**Annual growth rate**	
		2012	**2020**	**2030**	**2040**	**2050**	**2012-2030**	**2012-2050**
Heat	Industrial sectors wit	51 738	57 300	57 700	56 200	53 100	0.6 %	0.1 %
	Industrial sectors with increasing cogeneration2)	17 452	34 020	42 370	50 120	55 270	5.1 %	3.1 %
	Industry overall3)	**69 190**	**91 320**	**100 070**	**106 320**	**108 370**	**2.1 %**	**1.2 %**
	Unreported differences compared to statistics4)	14 935	17 597	21 600	22 949	23 392		
	Total potential of industry5)	**84 125**	**108 917**	**121 670**	**129 269**	**131 762**		
Electricity	Industrial sectors with stagnating cogeneration1)	19 690	23 540	23 910	22 810	20 610	1.1 %	0.1 %
	Industrial sectors with increasing cogeneration2)	5 158	16 780	22 590	28 010	31 600	8.6 %	4.9 %
	Industry overall3)	**24 848**	**40 320**	**46 500**	**50 820**	**52 210**	**3.5 %**	**2.0 %**
	Unreported differences compared to statistics4)	3 432	4 534	6 422	7 019	7 211		
	Total potential of industry5)	**28 280**	**44 854**	**52 922**	**57 839**	**59 421**		

1) Raw chemicals, stone/soil quarrying/other forms of mining and paper

2) Food and tobacco, automobile manufacture, glass and ceramics, rubber and plastic goods, machine engineering, metalworking, metal production, NF metals and foundries, other chemical industry, other branches of the economic and processing of stone and soil.

3) Total for industrial sectors considered in detail, excluding unreported differences compared to statistics

4) Difference is due to official statistics subject to confidentiality requirements.

5) Total for industry as a whole with unreported differences compared to statistics

Source: DESTATIS 2013 and 2014 a, b; VIK 2014, in-house calculations IREES 2014

6 Potential role of cogeneration in the future power and heat supply system

Requirements of the electricity system of the future

The growing proportion of fluctuating renewable energies on the electricity market presents the electricity system with three core challenges: Aside from preventing economically inefficient systematic electricity surpluses and refinancing of capacity backup on the electricity market, supply system services represent a core challenge. This imposes the flexibility requirements on cogenerated power production which are needed for its efficient integration in the energy system of the future.

Technical concepts for more flexible CHPP

Cogenerated power production, as part of what tend to be large heat supply systems in industry and in the general supply network using plant concepts, heat storage facilities and peak load boilers, offers enough technical flexibility to be able to survive in the long term, even in a system with high proportions of fluctuating renewable energies. The applications in property supply have the same technical flexibility options.

Current use of flexibility of CHPP to prevent down-regulation of RES plants

There does not appear at present to be any systematic inflexibility caused by cogeneration technology in the electricity system.
On the contrary, the generation profile of cogeneration in the general supply network in particular corresponds very well with input of renewable energies. There is therefore no cause to assume that the technical potential to make CHPP more flexibility in future has been exhausted. The fact that the technical potential for flexible operation of CHPP is not yet being fully exploited is due almost solely to the fact that they are not yet economically attractive. In particular, in the case of non-privileged end users and compared to plants marketed on the electricity market, private generation concepts react only in the case of very marked electricity price signals. However, these plants still account for a small proportion of the inventory (an estimated 15 TWh).

Cogeneration on the heat market

On the heat market, approx. 15 % is currently produced by CHPP. In the long-term and especially in densely populated areas, cogeneration offers a cheap and resource-efficient option for a low-CO_2 supply.

In the long term, however, the proportion of district heating supplied from RES should be increased in order to exhaust the potential on the heat side. In that context, power-to-heat concepts may also favour the integration of a higher proportion of fluctuating RES in the electricity market.

Long-term role of cogeneration in the overall system

From an historical perspective, the use of cogeneration technology has been restricted mainly by inadequate use of existing heat sinks. This restriction on the heat side will be compounded in the long term in future by increasing proportions of fluctuating renewable energy sources on the power side. With technical flexibility, CHPP will also make an economically sensible contribution to a cost- and resource-efficient supply of power and heat in the long term. By making use of additional flexibility options in the electricity system, such as cross-border electricity trading or the use of power-to-heat applications, it will be possible to develop the as yet untapped potential of cogeneration technology. The target system used to date to subsidise CHPP is proving to be unsuitable in the long term, due to the increasing proportion of non-cogeneration-compatible power generation technologies (wind and PV). Converting targets to cogeneration-compatible power generation would appear to make sense, given the growing proportion of fluctuating power generation.

CO_2 savings from cogeneration

Furthermore, cogeneration continues to make a clear contribution to CO_2 savings. Even if now only gas-powered plants are crowded out of the electricity mix on the German electricity market in the long term, there is still be a considerable advantage over uncoupled production in the CO_2 balance.

6.1 Requirements of the electricity system of the future

The German electricity system has changed enormously in recent years. Due to the development of renewable energy sources, the proportion of variable power production has increased enormously. In 2010, just under 8 % of the (gross) power produced in Germany was obtained from wind energy or photovoltaics. In 2013, it was already over 13 %. According to the calculations in the energy reference prognosis prepared for the Federal Ministry for Economic Affairs, the proportion of PV and wind power production will increase to over 50 % by 2050 based on the baseline scenario and trend extrapolation. The proportions in the target scenario are much higher.

Figure 29: Structure of power production in Germany 2010 to 2050

Structure of gross power production in Germany in TWh

Source: Prognos 2014 based on energy reference prognosis

The increase in fluctuating renewable power production gives rise to three fundamental challenges for the power system of the future to which CHPP are exposed.

Avoiding economically inefficient systematic power surpluses:

The spread of renewable, fluctuating power production means that load-following power production capacities will need to keep adapting better to the residual load (flexibilisation). With high RES deliveries by plants without short-term marginal costs, it makes sense to make less use of plants with marginal costs. For CHPP this means that in situations with high RES deliveries and low residual load, power production in CHPP should be as low as possible. CHPP, especially plants with a fixed power to heat ratio were not technically designed in the past to generate power as flexibly as possible.

Refinancing of backup in the electricity market:

Due to increasing power production from RES, the capacity utilisation of conventional plants on the electricity market has sunk considerably. With sinking CO_2 prices and slightly sinking overall demand for electricity, electricity prices on the wholesale market have plummeted due to the over-supply of energy. The resultant deterioration in the revenue position of conventional power plants, especially old plants with high variable costs, may result in coming years in an economically-driven decline in power plant capacity. However, that is offset by the continuing high demand for secured capacity in the electricity market to ensure that, in times of peak electricity demand, low-fluctuating renewable deliveries are available. Naturally wind and photovoltaics do little to back up generating capacity. This development has resulted in Germany in a situation in which the question is being discussed of whether capacity mechanisms are needed in the long term to back up the security of supply or if the energy-only market can provide sufficient back up in the long term on the supply and demand side. For CHPP, this means that, in times of high residual load, they must provide as much power production as possible in parallel to heat production. Here again, it would be helpful to increase the flexibility of CHPP, which historically has not been a focal point of plant design.

Increasing need for system services:

Power production from variable renewable energy sources, such as wind and photovoltaics, is must harder to predict than power production from load-following plants. Control power is needed to compensate for prediction errors. It is to be expected that, as regenerative power production develops, more control energy must be held in reserve, which in turn must be covered from the electricity system. In the past, conventional power plants and one-off large electricity customers were used for this almost exclusively. In future, however, it will be necessary to use more RES and CHPP, which in turn increases the need for a flexible cogeneration system.

In the long term, therefore, a certain degree of importance will be attached to making cogeneration systems more flexible, in order to favour the integration of high proportions of fluctuating renewable energies. There are various conceivable technologies and solutions for making CHPP more flexible. The technical design and use of such concepts is discussed in the following chapter.

6.2 Technical concepts for more flexible CHPP

Basically, technical concepts for CHPP differ in that they have either a flexible or a fixed **power-to-heat ratio**. CHPP with a flexible power-to-heat ratio include condensing steam turbines. Where there is a certain heat requirement, they can produce variable electricity in certain bandwidths from the district heating system. Therefore, it is possible in theory in such plants to adjust power production to the market situation. These plants are also mostly power-operated plants.

Plants designed with little flexibility and a fixed power-to-heat ratio include **backpressure machines, BHPP or gas turbines with heat recovery boiler**. The technical design of such plants is frequently predicated on the heat requirement and such plants are primarily heat-operated. However, this means that such plants cannot react to signals from the electricity market.

The AGFW annual report publishes the installed electrical capacity and power production by type of plant for CHPP in the general supply system (see Table 40). These statistics clearly illustrate that, as a rule, plants in the general supply system tend to have a flexible power-to-heat ratio. That means that there is also room for technical optimisation in relation to the electricity market.

Table 40: General supply CHPP (private plants according to AGFW) by type of turbine in 2012

	Flexibility power-to-heat ratio	**Electricity generation in TWh**		**Bottleneck capacity in GW**	
		Total	**in KWK**	**Total**	**in KWK**
Condensing steam turbine	Yes	84	9	13.7	3.9
Condensing G&S turbine	Yes	9	4	3.0	2.2
Gas turbine with heat recovery boiler	Yes*	1	1	0.9	0.9
Backpressure steam turbine	No	9	4	1.4	1.4
Backpressure G&S turbine	No	9	8	2.0	2.0
CHP	No	2	2	0.5	0.5
Total		**114**	**28**	**21.5**	**10.9**
with flexible ratio		**94**	**14**	**17.6**	**7.0**
without flexible ratio		20	14	3.9	3.9
*Assumption: Gas turbines are fitted with auxiliary coolers or can discharge heat via stack.					

Source: AGFW 2012

The flexibility of both designs can be improved by **using auxiliary coolers and heat storage facilities**. Naturally such systems have tended to be used primarily in the past in less flexible CHPP with a fixed power-to-heat ratio as they enable these plants which otherwise have little flexibility to optimise their use on the electricity market.

The addition of heat storage facilities as described in Chapter 7.4 has improved or will further improve the technical facility to make cogenerated power production in Germany more flexible. In small plants which supply a plot or block, heat and buffer storage facilities are fitted as standard. Thus, in principle, the technical facility also exists with these plants for optimal and more flexible use on the electricity market.

Only in industry have heat storage facilities tended to be the exception to date, as they are not economically viable at high temperatures. However, industrial plants, like all other CHPP, also use boilers to provide extensive backup for cogenerated heat capacity and potential peak loads. In principle, this allows the supply of power and heat to be optimised on the cost side. When wholesale prices are very low or negative, which tends to be a sign of high RES production compared to demand, it is also possible to shut down CHPP which are not very flexible and to generate heat using boilers and purchase electricity from the network. However, in CHPP which generate electricity for private use, this opportunity arises very late economically speaking. The network user fees saved or the levies and taxes at least partially avoided ensure that that opportunity only arises once prices are already highly negative. However, if such situations arise more frequently, industrial undertakings keen on economic optimisation will very quickly make use of such options.

Overall it can be assumed that the technical facilities to operate CHPP flexibly and thus prevent down-regulation of RES are very broadly exhausted. With the subsidies for heat storage facilities introduced in the last Cogeneration Act Amending Act has created additional potential here. Down-regulation of renewable power production based on technical inflexibility is therefore of secondary importance in our estimation.

6.3 Current use of flexibility of CHPP to prevent down-regulation of RES plants

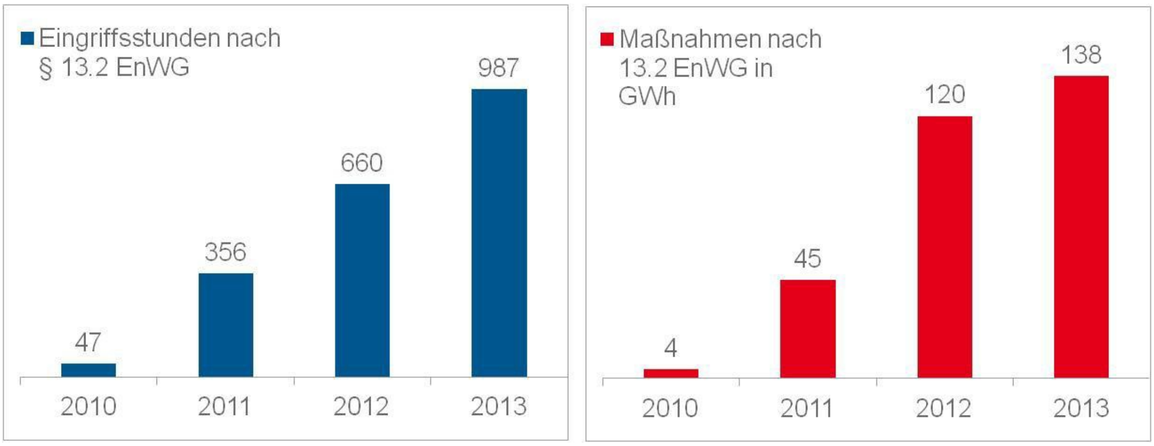
There may be temporary **surplus** production in electricity systems with a high proportion of renewable energies. That means that fluctuating power production and must-run production (to provide system services) exceed the current electricity requirement and the electricity cannot be integrated into the system and must therefore the down-regulated. However, down-regulation of fluctuating wind and PV energy should be the final possible option due to their marginal costs. A more flexible approach to (CHP) plants can reduce the occurrence of production surpluses.

However, such situations only occur when the proportion of fluctuating generating capacity is very high and have rarely been relevant in Germany to date. Even at times of high wind and PV deliveries, RES have never covered more than 65 % of the electricity requirement.

Local network congestion is another reason for down-regulation of fluctuating generation. As the location of wind farms and photovoltaic systems must be selected based on meteorological considerations, the electricity sometimes has to be transported to supply centres over long distances. Network congestion may mean that renewable electricity has to be down-regulated for reasons of network stability (Section 13.2 of the Energy Economy Act).

As Figure 30 illustrates, both the number of interventions and the absolute duration of interventions have increased considerably over the past four years: In 2013, a total of 138 GWh of renewable energy was down-regulated in approx. 1 000 hours. In 2010, it was just 4 GWh in 47 hours. It is to be expected in the medium term that network-related down-regulation of fluctuating power production will continue to increase, insofar as the network has not yet been developed sufficiently. As such down-regulation is applied solely due to technical network restrictions, even more flexible cogeneration cannot improve the integration of RES into the system here.

Figure 30: Network-related down-regulation of renewable energy sources in the transmission system (Section 13.2



EnWG)

	Intervention hours under Section 13.2 EnWG
	Measures under Section 13.2 EnGW in GWh

Source: Prognos AG presentation based on data from 50Hertz and TenneT

Electricity price-related down regulation within the framework of direct marketing is another reason why RES may be down-regulated. Under Sections 34 *et seq.* of the Renewable Energies Act (EEG 2014), revenue from electricity produced in direct marketing comprises the spot price achieved on the day-ahead market and the market premium. The market premium is determined monthly based on the applicable value (corresponds to remuneration under the RES Act) less the average revenue of the type of plant in question.

As a rule, contracts between direct marketers and plant operators are configured such that the plant operator at least receives the RES remuneration in each hour in which the plant can deliver. This means that the direct marketer bears the marketing risk. In hours with very negative prices, it may be more worthwhile for the direct marketer to shut down the plant due to electricity prices. In that case, the marketer must pay the plant operator the RES remuneration and does to receive a market premium from the network operator. At the same time, however, the marketer does not have to bear the costs of negative electricity prices. The threshold for shutdown is individual to each plant, as it depends on the applicable value. Such situations have rarely occurred to date.

The amended (2014) Renewable Energies Act also stipulates that the applicable value is reduced to zero for new plants in the event of six consecutive hours with negative spot prices. This is intended to act as an incentive to reduce RES power production in hours with negative prices. A flexible approach by CHPP would indirectly result in better integration of RES by reducing the supply on the market.

To summarise, this suggests that a flexible approach to date by CHPP has not had any or only a very small impact on down-regulation of renewable energies, as it was caused almost always by local network congestion. Only when surpluses occur in the system as a whole can more flexible cogeneration improve the integration of RES.

One indicator for the need for and availability of more flexible capacity in the electricity system is the changes in wholesale prices. Electricity prices well over EUR 100/MWh are a first sign that there is in theory little capacity to cover capacity in the system or that the capacity available is not reacting flexibly enough to electricity prices. Negative prices, on the other hand do not only indicate a lack of technical flexibility. They may also be caused by non-price-related offers by must-run power stations (power stations that supply control energy or CHPP), but are also a sign of missed opportunity. Nuclear and lignite-fired power stations with low variable costs and comparatively high start-up and power-down costs may be operated with optimum economic viability in periods of highly volatile prices if they accept few hours with negative electricity prices and thus spare start-up and power-down processes.

Table 41 illustrates the distribution of Epex Spot day-ahead market prices. Despite an increasing proportion of RES, there were comparatively few hours in recent years in which electricity prices were below EUR 0/MWh or above EUR 100/MWh. The highest numbers of negative electricity prices were in 2009, 2012 and 2013[8] , whereby the mean value of prices less than or equal to EUR 0/MWh was again much lower in 2013. In the past, the number of hours with electricity prices over 100 EUR/MWh has also dropped in the past.

This analysis suggests that existing power plants have sufficient power plant capacity to meet demand and react flexibly to the residual load in the system or that more flexible generation capacity is not necessarily needed at present.

Table 41: Absolute frequency of Epex Spot day-ahead prices between 2004 and 2013

Classes	2004	2006	2008	2009	2010	2011	2012	2013
Mean value of prices <=EUR 0/MWh	0	0	-12	-43	-5	-9	-58	-14

Hours <=EUR 0/MWh	0	10	35	73	12	16	58	65
Hours between EUR 0 and EUR 10/MWh	469	172	109	289	129	47	66	265
Hours between EUR 10 and EUR 20/MWh	1 324	431	123	485	284	219	492	747
Hours between EUR 20 and EUR 30/MWh	3 099	1 147	340	1 374	693	291	813	1 355
Hours between EUR 30 and EUR 40/MWh	2 719	1 858	751	2 714	1 827	809	2 445	3 006
Hours between EUR 40 and EUR 50/MWh	965	1 539	1 180	2 150	3 101	2 548	2 191	1 445
Hours between EUR 50 and EUR 60/MWh	121	1 086	1 402	807	1 729	2 539	1 729	1 079
Hours between EUR 60 and EUR 70/MWh	37	995	1 335	399	687	1 872	726	576
Hours between EUR 70 and EUR 80/MWh	17	593	1 226	251	224	362	115	140
Hours between EUR 80 and EUR 90/MWh	3	398	848	125	50	36	45	43
Hours between EUR 90 and EUR	3	265	523	48	17	10	20	22
Hours over EUR 100/MWh	3	266	888	45	7	11	60	17

Source: Prognos AG presentation based on data from Energinet.DK

6.3.1 Characteristics of current cogenerated power production

A distinction must be drawn between technical and economic aspects for the purpose of evaluating the current flexibility potential of CHPP on the electricity market.

First, plants must be equipped so that the heat supply can be uncoupled from power production. As described above, that may be achieved by using peak load boilers or heat storage facilities. Second, there must be sufficient economic incentive for plants to adjust to the residual load on the electricity market.

That means that, at times of high residual load, electricity price must be high enough to encourage delivery of the electricity to the network. By contrast, in the event of high deliveries from RES and low electricity demand, the electricity price must be low enough for cogenerated power production to be reduced and the electricity needed to be purchased from the network. The extent to which plants react to the situation on the electricity market depends on electricity prices (network) or the electricity price to be achieved on the wholesale market and the costs of the alternative heat supply (peak load boilers, storage facilities).

In order to outline the role of cogeneration in the changing electricity system, the current flexibilisation potential of various cogeneration classes are considered below. Particular focus is laid on cogeneration for general supply and industry cogeneration. They made the biggest contribution to cogenerated power production in 2012 (51.0 TWh and 28.3 TWh). Small CHPP of less than 1 MW_{el} and biogenic CHPP play a comparatively secondary role. Together they generated 15.7 TWh of combined power in 2012.

Table 42: Classification of CHPP

	Power production 2012 [TWh]	Typical mode of operation
Cogeneration for general supply	51.0	Overall optimisation in keeping with (spot) electricity prices and demand for district heating
Industry cogeneration	28.3	Heat-/power-operated depending on private requirement
Small-scale cogeneration > 1 MWel	4.5	Heat-/power-operated depending on private requirement
Biogenic cogeneration	11.2	Direct marketing/base load

Source: Prognos AG

The various cogeneration classes differ essentially in their power-to-heat ratio and thus in the way in which they are operated. In heat-operated mode, the focus is on covering the heat profile. The combined power product is either used privately or is delivered to the network. If the electricity requirement exceeds the power produced, additional electricity is purchased from the network. In power-operated mode, the plant is optimised to the electricity load profile or to spot prices. The heat is used privately and, if necessary, additional heat can be provided by a peak load boiler.

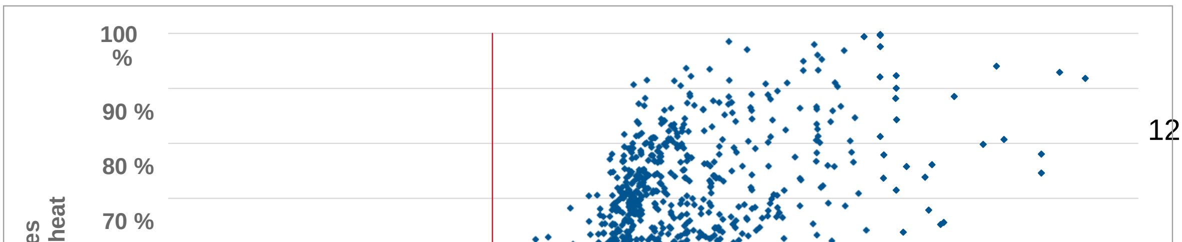
6.3.2 Cogeneration for general supply

Operators of general supply CHPP are required to meet the heat requirement of a specific district or local heating network. The heat required can be provided either by the CHPP or by a peak load boiler. The combined power produced is generally sold directly on the wholesale market (via the exchange or bilaterally).

Whether or not the CHPP in question is well integrated into the current electricity system in terms of its mode of operation basically depends on the extent to which the specific heat requirement correlates with electricity prices. Where high electricity prices occur simultaneously with a high heat requirement, that supports the electricity system stabilising mode of operation of the CHPP.

Figure 31 illustrates the correlation in time between the heat requirement of the Hannover district heating network and the day-ahead prices on the Leipzig electricity exchange for 2011 and 2012. What is striking is that, in times of high demand for heat, electricity prices tended to be over EUR 30/MWh. Negative electricity prices only occurred here and there; however, they were all within a maximum of 50 % of the maximum heat requirement.

Figure 31: Heat requirement of a real district heating network as a function of the Epex Spot day-ahead price in 2012

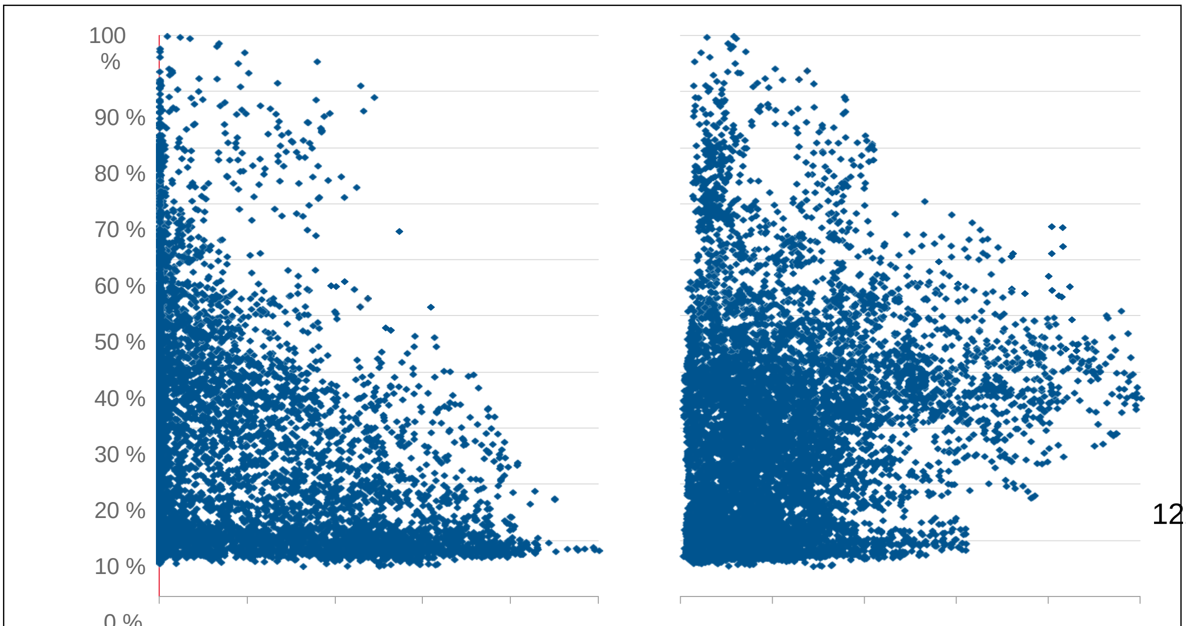


Source: Prognos AG based on Energinet.DK and public service figures

The distribution presented here is determined by the meteorological conditions, which result in a high heat requirement. High heat requirements mostly occur in the evening or early morning in winter under high pressure weather systems. Naturally, PV deliveries are very limited and even wind deliveries are generally low. This basically suggests that public supply CHPP are well adapted to the current electricity system.

The figure below, which maps the heat requirement of a district heating system compared to historic RES deliveries from wind and sun, illustrates once again the good compatibility of cogenerated production in the general supply system with fluctuating power production from wind and sun, as they tend to deliver the highest loads at times of lower heat load, i.e. there is a margin for heat-operated CHPP.

Figure 32: Heat requirement of a real district heating network compared to RES inputs from wind power and solar systems in 2012



Source: Prognos AG based on EEX-Transparency and public service figures

The decision on the mode of operation of CHPP in the public supply system is based specifically on overall optimisation of electricity revenue and heat production costs. That means that, when the mode of operation is decided, account is taken of the costs of heat and power production and revenue from electricity on the wholesale market, as well as the costs of alternative heat production in peak load boilers or use of heat storage facilities. Thus electricity price signals on the wholesale market are input directly into the calculation.

6.3.3 Industrial cogeneration

Operators of industrial CHPP generally have high process steam and power requirements. CHPP are used primarily in the raw chemicals, mineral oil processing, foodstuffs and paper industries. Whether the heat and power requirement is heavily structured or constant depends on the process and differs from branch to branch.

As a rule, industrial CHPP have one (or more) backup boilers which can cover the entire heat capacity of the CHPP to ensure the heat or process steam requirement. The mode of operation of CHPP is similar to that of public supply cogeneration (overall optimisation between electricity prices (network), private generation costs of heat and power, the costs of alternative heat generation and electricity revenue on the wholesale market).

Most industrial undertakings with private cogeneration power generation optimise their energy supply by taking account of network electricity prices, private generation costs of heat and power, the costs of alternative heat generation and electricity revenue on the wholesale market.

Optimisation in very large companies is generally assigned to an in-house trading department (e.g. Trimet, VW Kraftwerke, Currenta, DB Energie) which has its own trading desk or broker or is outsourced to third parties. In the case of medium-sized or small undertakings with their own CHPP, overall costs are generally optimised based on hourly wholesale prices. This is mostly done via third parties.

The costs of alternative heat production and the costs of power and heat production from the CHPP are comparable to the costs of public supply generation. Electricity prices to industrial customers comprise various components:

- energy procurement wholesale and distribution margin
- network fee

- fee for settlement, metering and meter operation
- concession charges
- RES levy

- cogeneration levy, offshore liability
- taxes (electricity and turnover taxes)

Depending on the quantity purchased and consumption structure, electricity prices paid by undertakings may vary considerably. However, the strongest lever is the RES levy, which is paid in part or in full depending on the relief and which is currently over 6 cents/kWh. Furthermore, network fees may also vary, depending on the voltage level to which the undertaking is connected. For electricity prices, that gives surcharges for electricity prices of approx. 1.0 to 3.5 cents/kWh on the costs of energy procurement for large industrial undertakings, depending on the supply level.

The degree to which a plant reacts flexibly to the electricity price depends in the case of low electricity prices on the electricity prices specific to the undertaking. The spot price has a much more direct impact on energy-intensive undertakings, which are privileged under the RES Act and enjoy beneficial network fees, than on non-privileged undertakings. However, with high electricity prices, which are designed to encourage delivery of unwanted electricity to the network, the spot price impacts the decision as to the mode of operation equally directly in all undertakings.

In 2012, net cogenerated power production was 28.3 TWh. Of that, 13.8 TWh was accounted for by chemical products, 5.1 TWh was accounted for by the paper industry and 3.3 TWh was accounted for by coke plants and mineral oil processing. The CHPP in these branches produce just under 80 % of industrial cogenerated electricity.

The undertakings in those branches have very high power consumption on average. In the chemical industry and in mineral oil processing/coke plants, annual cogenerated net power production per undertaking averaged approx. 250 GWh; in the paper industry it was 80 GWh per annum [Destatis; technical series 4, row 6.4].

In the chemical and paper industries, just under 28 TWh and 13 TWh respectively fell under the special compensation rule in the RES Act [BMWi, BAFA 2014]. That accounted for 70 % and 85 % respectively of network purchases by undertakings in those industries. As, historically speaking, CHPP were erected mainly in larger and energy-intensive undertakings, it can be assumed that most CHPP are to be found in the three branches which fall under the special compensation rule.

Electricity prices for those undertakings correlate directly with wholesale prices, due to the lower network fees (purchases at high- and medium-voltage levels) and relief from/reduction in levies and taxes. We assume that, for at least two-thirds of industrial cogenerated power production, the wholesale prices influence optimisation and planned use of CHPP.

That suggests that both cogeneration in the public supply system and most cogeneration in the industrial sector is already reacting sufficiently flexibly to electricity price signals.

Biogenic and small CHPP supplying plots and properties, which as a rule also have technical facilities such as storage facilities or peak load boilers, are increasingly included in the optimisation of the overall system via smart networks and virtual power plants. However, due to their dwindling importance in the system as a whole (17 TWh net power production or just under 3 % of overall net production in Germany), these plants can still be disregarded.

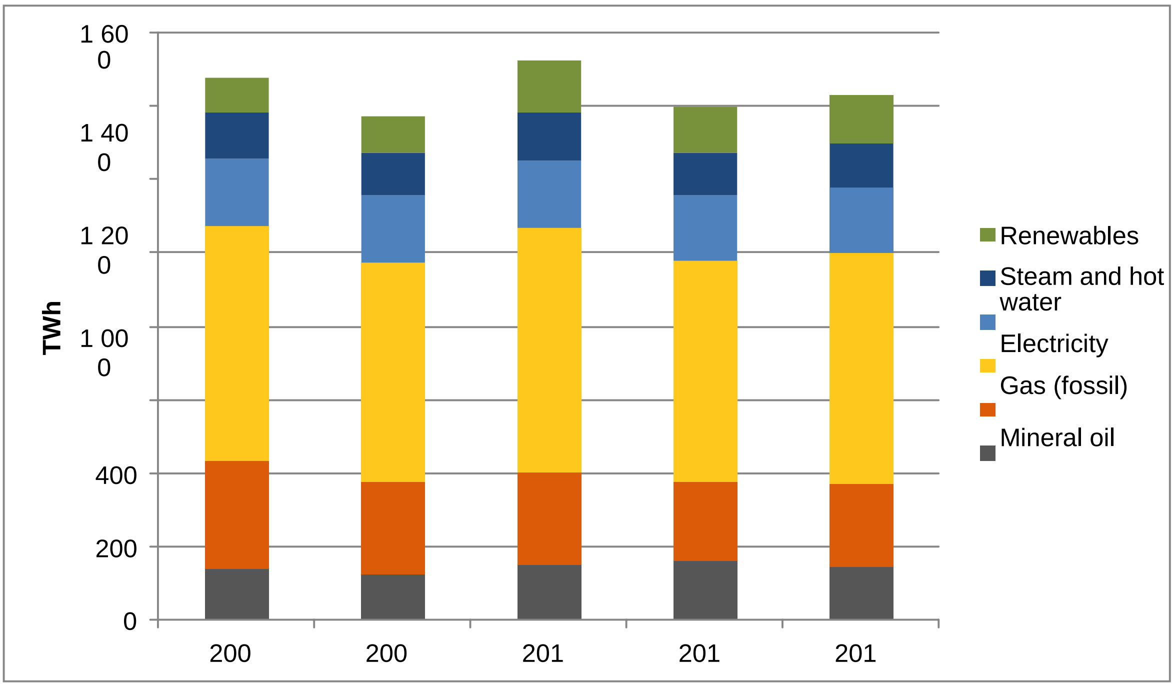
To summarise, it is technically feasible to make the cogeneration system more flexible. Moreover, that flexibility is also being used today where it makes economic sense to do so. The price signals in the electricity market are transparent and are included in the calculations made by undertakings when planning the use of CHPP. Systematic down-regulation of RES plants due to cogeneration deliveries is not expected. The little use made to date of the potential flexibility of cogeneration systems is primarily due to the fact that there is as yet no economic need. According to current information, there are no fundamental administrative obstacles.

With the flexibility in place, cogeneration can already and in future will significantly contribute to the supply of secured capacity and to the supply of system services.
At the same time, it should be noted that the use of various flexibility options in the electricity system may depress the economic viability of individual measures. For example, stronger networking of electricity markets in Europe in future will significantly reduce the volatility of prices in the market compared to a less networked system. Thus, investments in heat storage facilities to make use of the volatility of prices will be much less attractive. Coordinated subsidisation of flexibility options in the electricity system should therefore be the objective. Aside from coordinating subsidisation of heat and power storage technologies, that includes a comprehensive analysis of requirements for storage technologies in light of increasing European market integration which, with corresponding network development, offers considerable flexibility potential.

6.4 Cogeneration on the heat market

According to estimates by the Öko-Institut, CHPP produced 205 TWh of heat in 2012 [Öko-Institut 2014]. According to the application accounts published by AG Energiebilanzen, final energy consumption of heat in 2012 was approx. 1 430 TWh. The ratio of cogenerated heat production to the overall heat market was therefore approx. 14 %. Based solely on the heat requirement < 300°C, it was approx. 20 %.

Figure 33: Final energy consumption for heating, hot water, process heat, air-conditioning and process refrigeration by energy source



Source: AGEB 2013

CHPP in the heat supply sector tend to be an essential part of larger heat network systems. Thus CHPP are responsible for most district heating production According to AGFW, the ratio of cogeneration to heat network deliveries in 2012 was 82 %. Moreover, CHPP are used to produce process heat in industry.
Small mostly heat-operated CHPP are used to cover the heat requirement of larger buildings or properties. Often local heating concepts are applied. Most biomass CHPP are currently power-operated due to the RES subsidy but increasingly have heat-use concepts.

Fossil fuels continue to dominate the heat market. According to the application accounts of AG Energiebilanzen, the ratio of RES to final energy consumption for heat in 2012 was 9.2 %. The ratio of district heating to the heat market in that year was 8.2 %.

In order to achieve Germany's climate protection objectives, CO_2 emissions from the heat supply must be considerably reduced by 2050. In light of that, renewable energies and district heating from CHPP currently represent the most advantageous heat production technologies. Aside from improved efficiency of buildings and the increasing use of renewable energies, coupled district heat production can help enormously in reducing CO_2 emissions on the heat market.

In towns in particular, the potential for decentralised renewable energies for heat production is limited. District heating has the biggest potential in these dense areas to increase the efficiency of and reduce emissions from heat production. In the long term, more district heating must be provided by RES. The current ratio of RES to district heating is 9 % (AGEB application reports). There are no statistics available on the precise proportions of each renewable energy source. The largest proportion today, however, is accounted for by refuse, biomass and geothermal energy. According to the main AGFW report for 2012, approximately two-thirds of renewable fuels used in heat supply stations and CHPP are accounted for by refuse incineration and one-third by biomass plants.

Based on the rules in the 2014 RES Act, biomass-fired CHPP are not expected to increase to any noteworthy degree over the next few years. Even the refuse incineration sector will do little to drive development, as there is already excess capacity here.

The study ‘District Heating Transformation Strategies’ prepared by IFEU, the consultant engineers GEF and AGFW illustrates it is already technically and economically possible to integrate solar heat-fired plants and geothermal energy-fired plants into the cogeneration/district heating system. However, there are still only a few such plants in Germany:

- In 2013, there was a total of 27 geothermal energy-fired heat supply stations and CHPP with an installed heat capacity of just under 250 MW in operation. A further ten projects are currently under way and another 37 are being planned. However, the potential for large geothermal energy-fired plants is very limited in space.
- In Germany there are current 18 plants to produce solar district heating, each of which has a collector surface of at least 500 m². The biggest plants have capacity of up to 5 MW_{th}. The majority of these plants were erected between 1996 and 2000 within the framework of the Solarthermie 2000 and Solarthermie 2000plus subsidy schemes. When those schemes expired only a few new plants were built.

Plants which use RES in the heat market are currently subsidised under the Market Incentive Scheme (MAP) to support RES in the heat market. The Development Loan Corporation section of the MAP subsidises biomass-fired plants and heat pumps with over 100 kW_{th}, plants which use deep geothermal energy and solar heat plants with collector surfaces > 40 m² using repayment subsidies and soft loans. According to the BMWi, a total of 1 677 loans was granted under the Development Loan Corporation section of the MAP in 2013.

Approximately two-thirds were for heat networks. A total of 705 loans were for large biomass-fired plants and 59 were for large solar heat-fired plants.

Given the current basic conditions, we assume that there will only be a slight increase in RES in district heating.

Therefore it will only be possible to reduce the primary energy factor and CO_2 intensity of district heating by further increasing the proportion of combined and high-efficiency cogeneration in district heating networks. That is the main precondition to the continuing competitiveness of district heating in the heat market in light of the requirements of the Energy Savings Regulations and the Renewable Energies and Heat Act compared to other energy sources.

In the long term it is necessary and it makes sense to increase the ratio of RES in district heating. This could also be driven by power-to-heat concepts which use surplus energy with very high proportions of RES to favour the integration of high proportions of RES in power production. The first large-scale power-to-heat plants are currently being installed and tested in combination with heat storage facilities. In order to create the preconditions to the use of the long-term flexibility potential, the aim should be to continually develop district heating systems in conjunction with flexible CHPP technologies.

6.5 Long-term role of cogeneration in the overall system

The potential of combined heat and power production identified in Chapter 5 was extrapolated from a business and an economic perspective from the demand for heat.

In this chapter we **test** if the **potential** of cogenerated power production identified is **compatible overall** with the future **electricity requirement and electricity system** or if there are restrictions on the power side that will prevent the potential identified from being fully realised. The first step was to classify the potential identified in the overall electricity system. The second step was to validate the result against the results of a current investigation into cogeneration potential.

The scope of cogenerated power production is limited in the long term by the development of fluctuating renewable energy deliveries at times of sinking demand for electricity. In order to classify the potential, we determined the maximum quantity of electricity that Germany could generate now and in future in CHPP. The electricity scenarios from the current energy reference prognosis form the basis for the development of electricity production in Germany.

Future power production in Germany was classed as ‘cogeneration-

compatible' and 'non-cogeneration-compatible'. All energy sources or generating techniques which could be used for simultaneous power and heat production are 'cogeneration-compatible'. They include fossil fuel-fired power stations, nuclear energy, biomass, geothermal energy and other fuels. Power production from wind energy, photovoltaics, electricity storage facilities and hydroelectric power, on the other hand, does not generate any waste heat and cannot therefore be replaced by cogeneration.
That power production is classed as 'non-cogeneration-compatible' for the purpose of evaluating the potential for cogenerated electricity production.

Table 43 below illustrates overall electricity production in Germany for the trend scenario and the target scenario from the current energy reference prognosis up to 2050, subdivided into 'cogeneration-compatible' and non-cogeneration-compatible'. In both scenarios, the proportion of 'cogeneration-compatible' electricity production sinks over the long term due to the development of RES. It sinks from 521 TWh in 2013 to 253 TWh in the trend scenario and, even more sharply, to 147 TWh in the target scenario by 2050.

Table 43: Gross power production according to energy reference prognosis in trend and target scenario up to 2050, in TWh

	2013	2020	2030	2040	2050
Power production trend scenario	**631**	**618**	**612**	**565**	**561**
'Cogeneration-compatible'	521	439	381	325	253
Nuclear energy & fossil fuels	454	373	314	260	191
Biomass and other fuels	68	66	67	65	62
'Non-cogeneration-compatible'	110	180	230	241	308
Wind power & PV	83	156	210	222	282
Hydroelectric power and storage facilities	27	24	20	19	26
Power production target scenario	**631**	**576**	**516**	**466**	**459**
'Cogeneration-compatible'	521	378	271	210	147
Nuclear energy & fossil fuels	454	310	193	136	73
Biomass and other fuels	68	68	78	74	74
'Non-cogeneration-compatible'	110	198	245	257	313
Wind power & PV	83	173	225	237	289
Hydroelectric power and storage facilities	27	25	20	20	24

Source: Prognos, EWI, GWS 2014

This development is compared in Chapter 5 with the economic and business cogeneration potential determined and with the baseline and ambitious variation for industrial cogeneration potential (see Table 44). That comparison allows us to estimate how much cogeneration power production can be integrated in the electricity system (in a simplified annual balance) if all CPP could be operated flexibly.

In both the reference and the target scenario of the energy reference prognosis, the business potential of cogenerated power production of 165 to 173 TWh up to 2040 is less than ‘cogeneration-compatible’ power production. In 2050, the cogeneration potential determined is less than ‘cogeneration-compatible’ power production in the reference scenario but more than production in the target scenario.

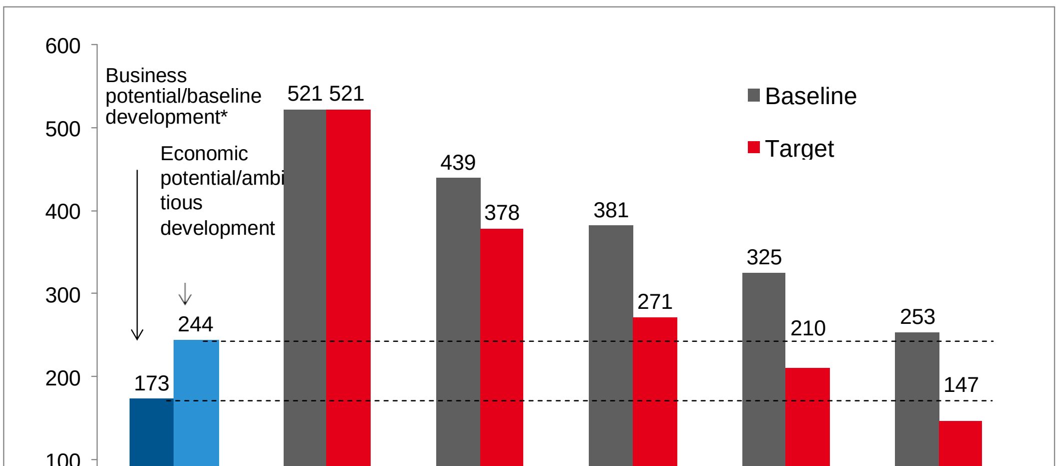
Cogenerated power production from an economic potential differs depending on the scenario: In the reference scenario, the potential of 230 to 244 TWh is less than ‘cogeneration-compatible’ power production in all years. In the target scenario, however, ‘cogeneration-compatible’ power production declines more quickly in that scenario due to lower demand for electricity and faster development of fluctuating renewable production in that scenario and, after 2030, will be less than economic potential. It would therefore not make sense to increase overall potential in that scenario.

Table 44: Cogenerated power production potential, in TWh

		2020	2030	2040	2050
Total	**Business/baseline variation**	**N/A[1]**	**170**	**173**	**173**
District heating cogeneration	business	N/A[1]	113	113	113
Property cogeneration	business	14	14	14	14
Industrial cogeneration	Baseline variation	38	43	46	46
Total	**Economic/ambitious variation**	**N/A[1]**	**238**	**243**	**244**
District heating cogeneration	economic	N/A[1]	182	182	182
Property cogeneration	economic	3	3	3	3
Industrial cogeneration	Ambitious variation	45	53	58	59

[1] District heating cogeneration potential can only be realised in full once all existing heating has been replaced.
Source: Prognos, IFAM, IREES

Figure 34: Comparison of cogeneration potential and development of cogeneration-compatible power production



* Economic/business perspective for property and district heating cogeneration, baseline/ambitions development for industrial cogeneration

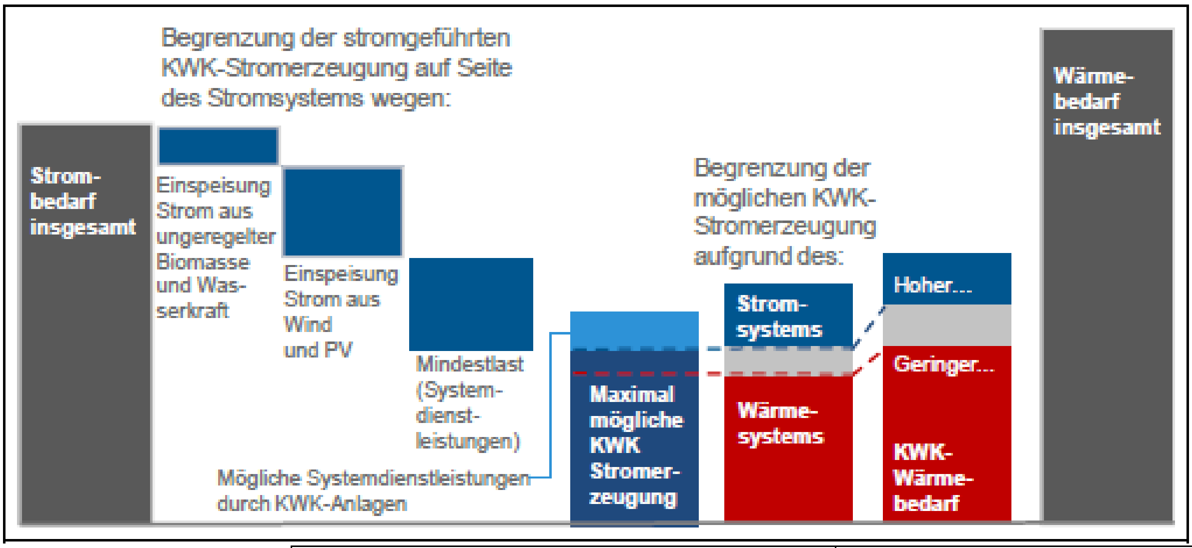
Source: IFAM, IREES 2014, Prognos, EWI, GWS 2014

Annual ‘cogeneration-compatible’ power production forms the upper limit on possible cogenerated production. The success of cogenerated power production should therefore be measured against that power production and not overall power production. Therefore it would be conceivable to define the 25% target laid down in current policy against cogeneration-compatible power generation over an appropriate long term.

However, aside from annual over power production, the hourly demand for heat and the hourly residual demand for electricity limit the potential to use CHPP. The study entitled ‘Measures for the sustainable integration of systems for coupled power and heat supply in the new energy supply system’ for the BDEW [Prognos 2013] investigated the usable potential for coupled power and heat production on CHPP for the period up to 2050.

One fundamental premise of the calculations was to prevent RES electricity deliveries from being crowded out by the use of cogeneration and to meet the demand for heat of users connected to cogeneration systems at all times. The use of cogeneration was modelled for that period on an hourly basis. It therefore illustrates the cogeneration potential obtained as the quasi lowest common denominator of the power and heat market (see Figure 35).

Figure 35: Electricity- and heat-side limitation of cogenerated power production



	Total electricity requirement
	Limitation of power-operated cogenerated power production on the electricity system side due to:
	Deliveries of power from unregulated biomass and hydroelectric power
	Deliveries of power from wind and PV
	Minimum load (system services)
	Limitation of potential cogenerated power production due to:
	Maximum possible cogenerated power production
	Heat system
	Cogenerated heat requirement
	Total heat requirement
	Higher...
	Electricity system
	Lower...

Source: Prognos 2013

The scenarios investigated assumed an increasing proportion of renewable energies in power production. In 2050, the proportion of renewable energies was approx.
80 %.

Depending on the development of district heating networks assumed, a maximum usable cogenerated power potential of 140 TWh in 2030 and 107 TWh in 2050 was determined in the study. It was assumed that the flexibility of CHPP and the electricity system would improve compared to the current situation.

In comparison to the increased potential in this study, the picture is as follows:

Of the potential determined, roughly 62 % could be integrated into the future power and heat system from a business perspective and approx. 44 % from an economic perspective.

The potential determined in this study cannot be fully realised from that perspective. However, with the following measures and developments, the use of cogeneration potential could probably be increased considerably:

- a higher proportion of ‘cogeneration-compatible’ technologies (geothermal energy, biomass) replaces fluctuating RES production when renewable energies are developed and increases cogenerated power production;

- increasing power exchanges due to more European networking reduces the simultaneity of fluctuating RES power production and thus increases the potential for cogenerated power production;
- rising electricity consumption in Germany and neighbouring markets, e.g. due to increase in electro-mobility, heat pumps and use of power-to-heat applications in district heating systems or industrial processes favours utilisation of cogeneration potential.

The results of the potential estimates made in this study need to be classified in a detailed scenario analysis of the energy system as a whole. Studies to date (e.g. reference prognosis) only investigate worlds with much lower cogeneration potential compared to the potential determined.

6.6 CO_2 savings from cogeneration

Coupled power and heat production saves fuel and CO_2 emissions in cogeneration systems compared to uncoupled production. The saving made depend on the reference system in question. The range of CO_2 savings made by cogeneration systems in 2012 is presented in current studies.

[Öko-Institut 2014] calculates CO_2 savings by comparing emissions from coupled production to emissions from separate power and heat production. CO_2 emissions from power production are calculated based in relation to the specific emission factors of the individual fuels. Reference heat production corresponds to the mix of alternative heat production. For the reference power production, cogenerated power production is divided into a flexible and a non-flexible part. In total, CO_2 emissions of just under 40 million t CO_2 are saved. [Prognos 2013] assumes for all consumer groups that the operation of CHPP crowds out conventional production rather than RES power production. The resultant higher specific power reference emission factor gives CO_2 savings of 56 million t CO_2 for 2012.

Aside from CO_2 emissions, coupled production saves other emissions, such as sulphur dioxide, dust and NO_x. In general, emissions are lower compared to uncoupled production, as less fuel is used. In urban areas in particular, the lower emission limit values and better treatment of exhaust gas by CHPP has a positive impact on air quality compared to individual heating.

Even today, cogeneration is dominated by an environmental-friendly fuel (natural gas). We assume that the proportion of natural gas will increase further during coming decades. The following fuel proportions have been assumed for our calculations for cogeneration as a whole (district heating, property and industrial cogeneration):

Table 45: Fuel mix of CHPP

Fuel	2012	2020	2030	2040	2050
Natural gas	53 %	59 %	63 %	67 %	71 %
Coal	22 %	17 %	13 %	10 %	6 %
Lignite	6 %	6 %	5 %	4 %	4 %
Biomass	2 %	4 %	5 %	6 %	7 %
Waste	7 %	8 %	7 %	7 %	7 %
Petroleum	1 %	1 %	1 %	1 %	1 %
Rest	9 %	6 %	6 %	5 %	5 %

Source: Prognos 2014

In order to calculate **CO_2 emissions from cogeneration**, the power and heat quantities determined in the potential analysis are multiplied for each fuel by the mean efficiency of energy use of cogeneration. That gives the fuel used, which is multiplied by its specific emission factor. The total across all fuels used gives the CO_2 emission from cogeneration.

In order to **calculate the CO_2 emissions of uncoupled production**, a notional crowding out of mean emissions from power and heat production by cogeneration is assumed.

The model assumes for all consumer groups that the operation of CHPP crowds out conventional production rather than RES power production. However, the marginal costs of cogeneration tend to be higher than the marginal costs of nuclear power plants, meaning that crowding out of nuclear energy by cogeneration is unrealistic and has thus been disregarded in the fuel mix crowded out. These preliminary considerations give a **power-reference emission factor (net power production)** of 912 g CO_2/kWh today, which declines over the years up to 2050 due to the change in production mix. Moreover, a new gas-fired plant with an electrical efficiency rating of 50 % was considered as the power production reference as a lower estimate for potential CO_2 savings.

A distinction is made for the purposes of **reference heat production** between industrial heat production and heat production in the private household (PHH) and commerce/trade/services (CTS) sectors.

In **private households and CTS buildings**, the mean emission factor obtained from average fuel use and the fuel efficiency of heating systems is currently 261 g CO_2/kWh. That assumes that the alternatives to district heating in such buildings are primarily fossil fuels. Heat pumps and individual heating in one-family houses are mostly not being crowded out by district heating and are therefore not included in the crowding-out mix from CTS and AB. Table 46 illustrates changes up to 2050, which are also marked by a trend towards a higher proportion of gas-fired heating.

For **industrial cogeneration**, the reference heating mix of coal, oil and gas for heating, hot water and process heating is based on conversion efficiency of 90 %. Specific emissions are somewhat higher today than in the building sector (275 g CO_2/kWh) and fall more slowly (see Table 46).

Table 46: Emission factors of uncoupled reference power and heat production

Emission factor		**2012**	**2020**	**2030**	**2040**	**2050**
Cogenerated power crowding-out mix	g CO_2/kWh	912	810	737	714	661
Cogenerated power gas-fired plant	g CO_2/kWh	400	400	400	400	400
Heat district heating/property supply	g CO_2/kWh	261	236	221	217	215
Heat industry	g CO_2/kWh	275	270	263	258	253

Source: Prognos 2014

Potential additional CO_2 savings in the cogeneration system from the use of surplus electricity (power-to-heat) have been disregarded here, as the surpluses available were not estimated in this study.

In the **base year** (2012), CO_2 savings from coupled production in CHPP compared to uncoupled reference production were approx. **56 million tonnes**. Figure 36 illustrates the potential emission savings for the period up to 2050.

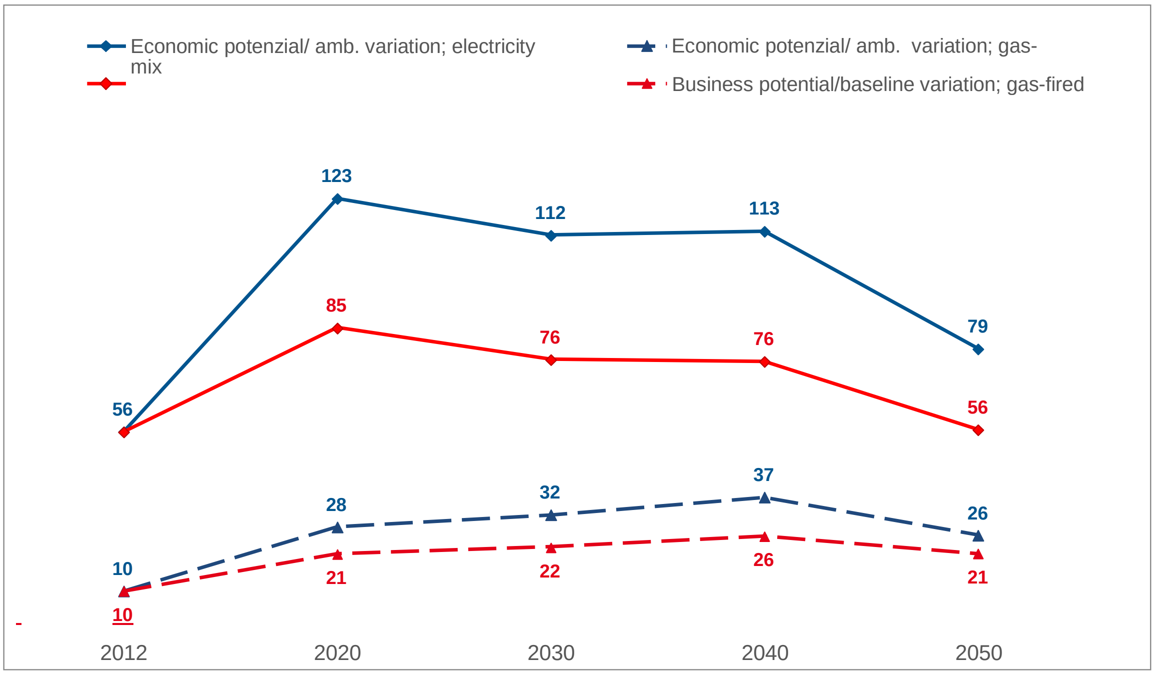
If sensible cogeneration potential from a business perspective is realised (baseline variation of industrial cogeneration) and the electricity crowding-out mix is applied, the cogeneration system will be able to save up to 85 million tonnes CO_2 a year. By 2050, absolute savings fall back to current values due to more efficient reference systems with lower CO_2 emissions. However, in relation to the overall emissions budget that Germany can initiate, absolute savings in 2050 will be higher than current savings.

If Germany succeeds in tapping sensible cogeneration potential from an economic perspective (ambitious scenario for industrial cogeneration), even higher CO_2 savings are possible. Savings would then be between 123 million tonnes in 2020 and 79 million tonnes in 2050.

If cogeneration does not crowd out the electricity mix assumed here, the cogeneration system will make other CO_2 savings. Therefore a new gas-fired plant with an electrical efficiency rating of 50 % was considered as the power production reference as a lower estimate for savings. Even this (by today's standards) very low CO_2 emission fossil fuel power production system saves cogeneration CO_2 ein. These savings between 2020 and 2050 are between 21 and 37 million tonnes a year.

Additional CO_2 savings from the cogeneration system would be possible with greater use of renewable energies in CHPP and the district heating system. In particular, large solar heat plants, geothermal plants and power-to-heat technologies and increased use of biomass will help to further decarbonise the cogeneration system. However, this study does not focus on increased use of these
options. Potential additional CO_2 savings are therefore disregarded.

Figure 36: CO_2 emissions avoided during cogeneration at calculated potential (estimated cogeneration electricity crowding-out mix compared to a new gas-fired plant) in millions of tonnes of CO_2



Source: Prognos 2014

7 Review of Cogeneration Act

Ratio of cogeneration to overall power production

In 1986, with net electricity production of 96.4 TWh (2003: 82.4 TWh), cogeneration accounted for approx. 16.2 % (2003: 14.2 %) of net electricity production in Germany. CO_2 savings from combined production in CHPP, compared to uncoupled reference production, were approx. 56 million tonnes in 2013.

CHPP subsidised under the Cogeneration Act

The 2009 Cogeneration Act Amending Act increased subsidised additions and modernisation together to a level of over 500 MW per annum. Following the amendments to the Cogeneration Act in 2012, that value rose in 2013 to just 1 100 MW, due mainly to the increasing volume of modernisations of plants of over 2 MW.

Property and industrial cogeneration have grown dynamically in recent years, with the 50 kW to 2 MW capacity segment recording the highest growth rate. The increase in the cogeneration surcharge under the 2012 Cogeneration Act Amending Act and the sharp increase in the RES levy, which may private use of the electricity generated more economically attractive, were probably responsible for that growth.

Heating and cooling networks subsidised under the Cogeneration Act

Between 2009 and 2011, an average of 400 km of lines were commissioned. Following the amendments to the Cogeneration Act in 2012, that value jumped to a good 800 km of lines per annum.

Newbuilds, extensions, network mergers and network development are subsidised; most important are extensions, which account for 54 % of line kilometres, and newbuilds, which account for 40 %. No cooling networks have been subsidised to date.

Heat and cooling storage facilities subsidised under the Cogeneration Act

Since that subsidy was introduced, 89 storage projects with a total storage capacity of approx. 8 100 m³ have been completed. A further 81 heat storage facilities with a capacity of approx. 53 000 m³ are still in the approval procedure. Plans to build numerous additional storage facilities with capacity of approx. 230 000 m³ have also been announced. To date only heat storage facilities have been subsidised.

Economic viability of CHPP

The only public district heating supply plants which can break even in the short term (up to 2020) under the basic conditions described are modern coal-fired CHPP. Without subsidies, gas-fired CHPP are not economically viable in any of the cases considered. Only plants with a high electrical efficiency rating in some years can achieve a positive contribution margin. As of 2017, as gas and electricity prices converge further, it will no longer be possible for any plants to achieve that. Newbuild public CHPP for district heating cannot be refinanced at present.

Larger property and industrial CHPP, on the other hand, can be erected and operated in suitable applications under present subsidy law. Numerous applications achieve a sufficiently high rate of return on the project without any cogeneration subsidy.

Consumers in energy-intensive industries enjoy relief on levies and electricity is therefore cheap to buy; therefore, although a new CHPP would be expected to generate a positive rate of return on the project, it would tend to be below the minimum rate of return for implementing the project. Adjusting subsidies could generate new momentum in this segment.

Smaller plants, especially in residential properties do not achieve a positive rate of return under current conditions. With a negative rate of return on projects, plants are only built here and there based on non-monetary criteria.

For small to medium-sized plants supplying properties, economic viability depends enormously on the rate of private use of electricity. Very good rates of return on projects can be achieved in certain applications, such as hotels or hospitals. In sectors such as the residential sector, however, projects are very hard to implement.

Cogenerated power production prognosis up to 2020

Net cogenerated power production will remain more or less at current levels up to 2020. For CHPP for general supply, the economic situation will probably cause a decline in cogenerated power production, whereas a slight increase compared to current levels is anticipated for industrial and property cogenerated power production up to 2020. Following the changes made in the 2014 RES Act, only a few newbuild biogenic CHPP are expected over the next few years.

The Cogeneration Act provides for an interim review in 2014. The objective is to investigate the degree of attainment of the energy and climate policy objectives of the Federal Government, the basic conditions for the operation of CHPP and the annual surcharge payments.

Further technological progress has been made with CHPP even in recent years. The electrical efficiency of new CHPP has increased across almost all capacity ranges. In the low capacity range, more and more CHPP are being fitted with condensing technology as standard. The number of modules available in the < 50 kW capacity range has almost doubled in five years. Due to further developments in the low capacity range following the market entry of combustion engines and Stirling engines with capacity of up to 2 kW, even one-family houses with a small heating energy requirement can be supplied with heat and power by these micro-CHPP.

On the one hand, the implementation of fossil fuel-fired CHPP in the property and district heating supply within coming years will allow a considerable reduction in CO_2 to be achieved immediately by developing high-efficiency decentralised power and heat production.

On the other hand, this is already creating structures which will make it relatively easy in the medium term to make use of new technical developments in CHPP constructions, such as fuel cells. Moreover, it would already appear to be technically feasible and, within the framework of the energy transition, likely in the medium term that future CHPP will use more biomethane produced from biomass, wind power or PV power (power-to-gas) and distributed via the current natural gas network.

The following chapter describes the development of cogenerated power production over the past ten (Chapter 7.1) and evaluates the CHPP, heat and cooling storage facilities and heating and cooling networks subsidised under the Cogeneration Act since 2003 or 2009 (Chapter 7.2 to 7.4). That information and the economic viability calculations performed (Chapter 7.5) are used as the basis for a prognosis of cogenerated power production and the costs of the Cogeneration Act levy up to 2020 (Chapter 7.6). This is followed by recommendations for the further changes to the Cogeneration Act (Chapter0).

7.1 Ratio of power production in CHPP to overall power production

The development of cogenerated power production is an important indicator of the situation of cogeneration overall and in the individual orders of magnitude and applications. It can provide initial clues to the economic situation of cogeneration and the efficacy of cogeneration subsidies in terms of development of the cogeneration system. Furthermore, the ratio of cogenerated power production to overall power production in Germany is the most important criterion against which to measure the cogeneration development target (25 % in 2020).

Table 47 below shows cogenerated power production from 2005 to 2013. The data are based on monthly electricity supply reports (technical series 4, row 6.4) of the Federal Statistical Office and calculations by the Öko-Institut. Plants are subdivided by operator, size class and fuel used and in groups (general supply power plants above and below 1 MW_{el}, industrial cogeneration and biogenic cogeneration). Biogenic cogenerated power production, which is not included in public statistics on industry and general supply, was determined by the Öko-Institut for the period from 2005 to 2012. The missing values for 2013, before publication of standardised cogeneration statistics, have been extrapolated here based on anticipated additional plants. For general supply plants below 1 MW capacity,
these are the BAFA figures based on the corresponding additional plants and, for industrial cogeneration, the figures based on changes in power production as a whole in Germany. For biogenic CHPP, a

constant cogeneration ratio was assumed and cogenerated power production was calculated in those years based on changes to biogenic power production as a whole.

Based on these assumptions, overall cogenerated net power production rose between 2005 and 2013 by 15 TWh, from 82.4 TWh to 96.4 TWh. The cogeneration rate rose over the same period to 16.2 %. The most dynamic growth was in biogenic cogeneration, which profited from RES remuneration. It rose dynamically from 3.2 TWh in 2005 to 12 TWh in 2013. Production in small fossil fuel-fired CHPP doubled over the period considered to 4.9 TWh. Cogeneration for general supply fell slightly after 2011 and fell in 2013 to 49.7 TWh, its lowest value since 2005. Power production in industrial cogeneration rose continuously from 25.6 TWh to 29.7 TWh.

Table 47: Cogenerated net power production 2005 to 2013

	2005	2006	2007	2008	2009	2010	2011	2012	2013
Net electricity production	582	597	599	599	558	591	574	591	595
Net cogenerated power production	**82.4**	**86.9**	**86.5**	**89.2**	**89.2**	**97.0**	**94.1**	**95.1**	**96.4**
General supply	51.5	54.0	51.9	53.8	50.5	53.3	50.9	51.1	49.7
Coal	13.7	12.4	11.1	11.2	11.6	13.3	12.1	12.8	13.7
Lignite	3.8	3.7	3.7	3.8	3.7	4.2	4	4.2	4.5
Mineral oil	0.7	0.3	0.2	0.1	0.2	0.2	0.3	0.1	0.1
Gas	31.4	35.1	34.1	35.3	31.2	31.5	30	28.9	25.8
Renewables	0.4	0.5	0.6	0.9	1.2	1.3	1.5	1.7	2.2
Rest	1.6	2.1	2.3	2.5	2.6	2.8	2.9	3.3	3.4
Industrial cogeneration	25.6	25.8	25.8	25.7	26.6	29.8	28.4	28.3	29.7
CHPP under 1 MWel	2.1	2.2	2.4	2.7	2.9	3.3	3.8	4.5	4.9
Biogenic cogeneration*	3.2	4.9	6.4	7.0	9.2	10.6	10.9	11.2	12.0
Ratio of cogeneration (to net production)	**14.2 %**	**14.5 %**	**14.4 %**	**14.9 %**	**16.0 %**	**16.4 %**	**16.4 %**	**16.1 %**	**16.2 %**
*Biogeneic plants not included in statistics on general supply or industry									

Source: Stabu 2014, Monatsberichte E-Versorgung 2014, Öko-Institut 2014

Cogenerated power production in the general supply system is illustrated in Table 47 by energy source. Coal-based production was almost the same in 2013 as in 2005, at 13.7 TWh, although it was somewhat lower in the intervening years. Lignite production rose slightly in recent years to 4.5 TWh (2013).

What is striking is the sharp decline in natural gas-fired production in CHPP, which fell from 35.3 TWh in 2008 to 25.8 TWh in 2013. This was possibly caused by sinking revenue from sales of electricity alongside constant to slightly rising gas prices. However, cogenerated power production from renewable and other energy sources reported in the statistics rose continuously over that period

from 0.4 and
1.6 TWh respectively to 2.2 and 3.4 TWh respectively in 2013.

7.2 Newbuild and modernised CHPP subsidised under the Cogeneration Act

The current version of the Cogeneration Act lays down several subsidisation criteria, which can be differentiated as follows:

- Newbuild: Section 5(1) and (2) recognise a claim to payment of the surcharge for cogenerated power from high-efficiency plants commissioned for continuous operation from 1 January 2009 to 31 December 2020.
- **Modernisation:** Section 5(3) of the Cogeneration Act allows the parts of a modernised CHPP that determine its efficiency to be subsidised as a 'modernised' plant. The subsidy is granted for varying periods of time, depending on the modernisation costs. A distinction is made in terms of modernisation costs between two brackets: 'at least 50 % of newbuild costs' and 'at least 25 % of newbuild costs'.
- **Retrofitting:** Section 5(4) of the 2012 Cogeneration Act recognises a claim to payment of the surcharge for cogenerated power from uncoupled power or heat plants in which components for power or heat uncoupling have been retrofitted, if the retrofitted plant has electrical capacity of more than 2 MW. That rule is intended, among other things, to allow for subsidisation where a steam turbine in an existing steam boiler is retrofitted.

The figures below illustrate the additional, modernised and retrofitted CHPP subsidised under the Cogeneration Act. The data provided by BAFA were evaluated for the purpose. The data set on the CHPP subsidised or applied for are dated 16 April 2014. The data sets on networks and storage facilities are dated 30 July 2014 and include all information available on 1 July 2014.

These data include all subsidised CHPP operated using conventional energy sources. They do not include CHPP subsidised under the RES Act or CHPP whose operators did not apply for a subsidy under the Cogeneration Act, although that most probably only applied to very few plants.

The 2009 Cogeneration Act Amending Act increased subsidised additions and modernisation together to a level of over 500 MW per annum (see Figure 37). After the 2012 amendments, the capacity of subsidised modernised and newbuild CHPP rose in 2013 to just under 1 100 MW. That increase was accounted for primarily by an increase in modernised plants > 2 MW. Retrofitting has only be subsidised once for a 6 MW steam turbine. 'Retrofitting' as a subsidy criterion plays no role in its current version within the subsidisation scheme in the Cogeneration Act.

Figure 37: Newbuild and modernised CHPP subsidised under the Cogeneration Act in MW in 2003 to 2013 (includes plants already licensed and licensing applications not yet fully processed)

Source: Prognos 2014

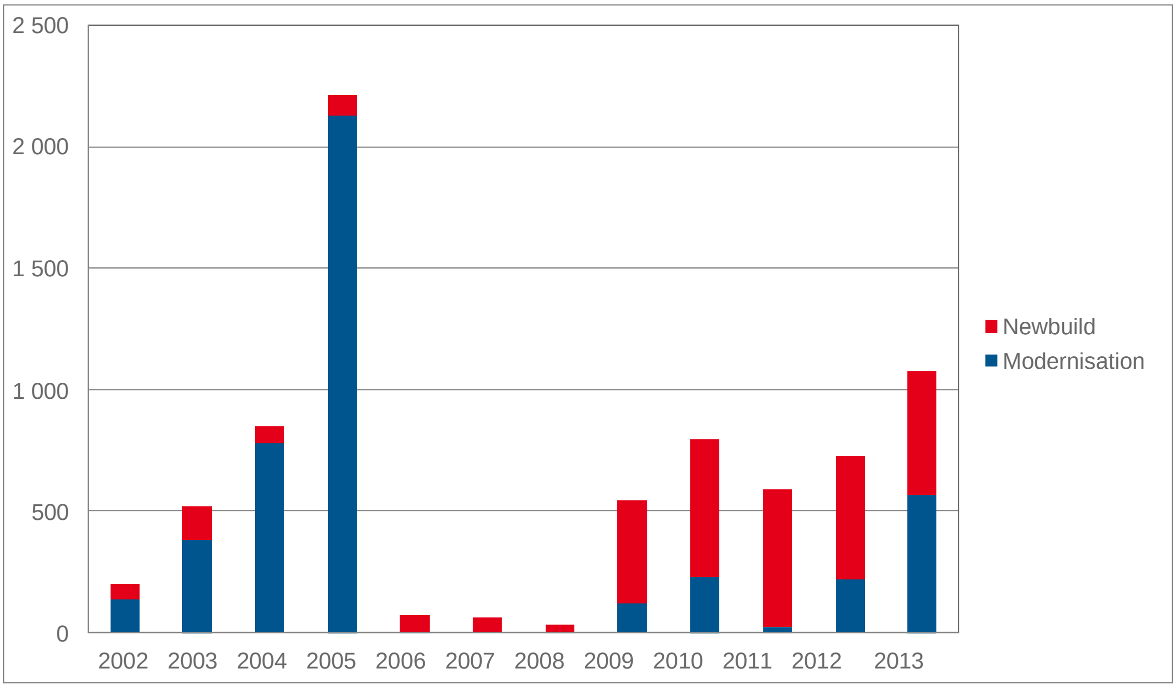


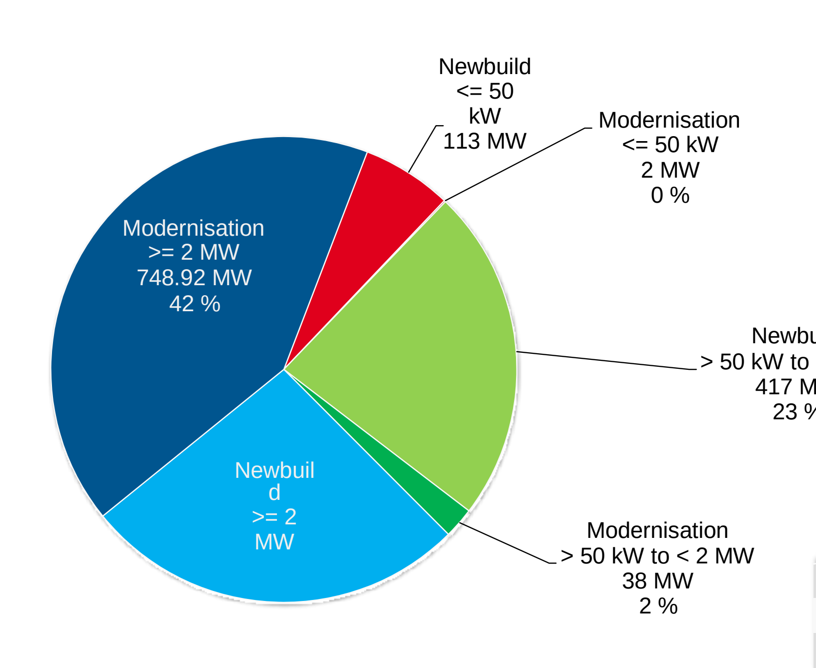
Figure 38 illustrates the percentages of newbuilds and modernisation in the three size classes ('less than or equal to 50 KW', 'greater than 50 kW to less than 2 MW' and 'greater than or equal to 2 MW' in 2012 and 2013, i.e. after the 2012 Cogeneration Act Amending Act.

Modernisation of plants of over 2 MW electricity capacity accounts for 42 % of all cogenerated capacity subsidised over this period. Newbuilds in this size segment account for 27 % of the cogenerated capacity subsidised. Modernisation plays only a minor role in ranges below 2 MW. Newbuild plants in the middle size class account for approx. 23 % of the cogenerated capacity subsidised and the small segment accounts for approx. 6 %.

One plant has been licensed in the 'retrofitting' sector since 2012. It was a 6 MW steam turbine.

Figure 38: Newbuild and modernised CHPP

subsidised under the Cogeneration Act in MW in 2012 and 2013 (includes plants already licensed and licensing applications not yet fully processed)



	Capacity in MW
Modernisation	789
Newbuild	1 008
Total	1 797

Source: Prognos 2014

In the capacity segment < 50 kW (see Figure 39), the market volume subsidised in 2012 and 2013 was 53 MW and 61 MW respectively. Micro-plants with capacity of up to 2 kW have become visible in the market since 2010 and, with just under 1 900 plants in 2013, they accounted for just under one-quarter of subsidised plants and new subsidised capacity accounted for approx. 0.1 % in 2013. This capacity class covers a broad technological spectrum, from Otto engines through Stirling engines to fuel cells. These are at or just before the marketing stage and should be given particular attention over coming years with a view to decentralised supply solutions in sparsely occupied areas.

In 2009, additions in the capacity segment < 50 kW made a quantum leap and, with just over 55 MW, were double as high as the average in previous years. In the following year, additions fell markedly to approx. 40 MW, but then rose again and, by 2011, had reached 52 MW, i.e. close to the 2009 level. The biggest addition since 2002 was reported in 2013 (61 MW). The peak in 2009 was due to the fact that the 2009 Cogeneration Act Amending Act coincided with the start of the mini-cogeneration incentive scheme (climate protection initiative). However, the incentive scheme was suspended at the end of 2009, resulting in the sharp drop in 2010. The sharp increase in the RES levy between 2010 and 2014 and the increase in the cogeneration levy under the 2012 Cogeneration Act Amending Act were probably responsible for that renewed increase, as they made private use of the electricity generated more economically attractive.

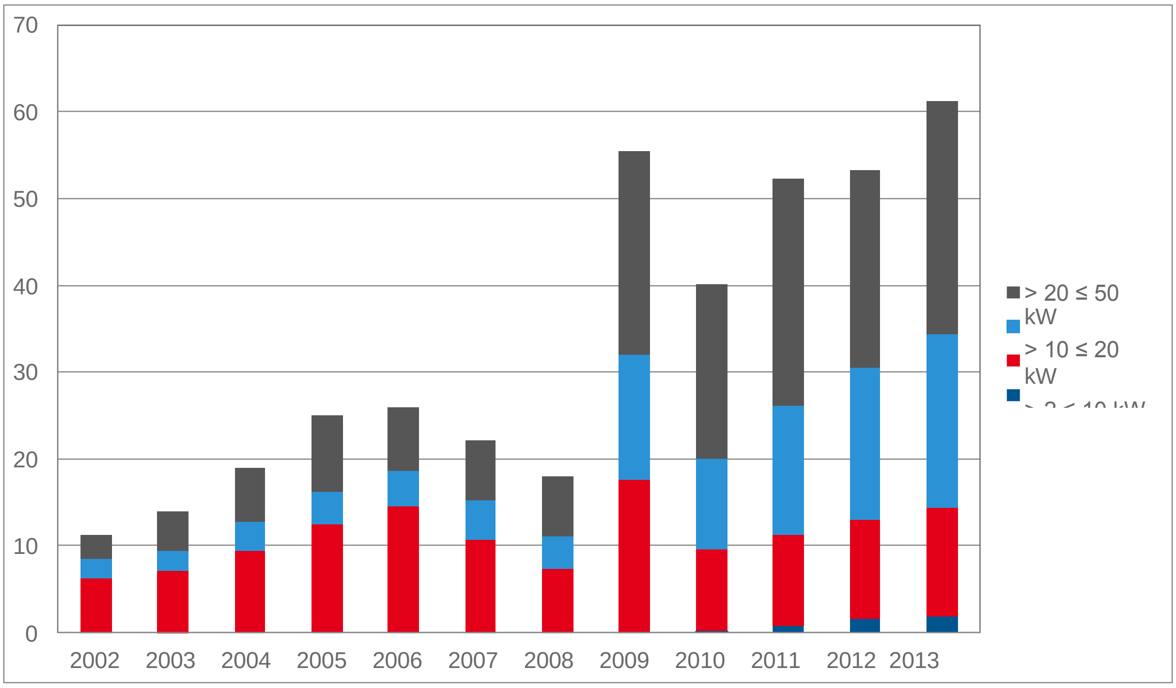
Section 7(3) of the current Cogeneration Act allows operators of micro-CHPP with electrical capacity < 2 kW to arrange to be paid an advance flat-rate supplement for cogenerated electricity for 30 000 hours' full load operation at the request of the network operator.

According to BAFA statistics, of the 3 435 online notices issued up to 8 September 2014 in accordance with the general decree for plants < 2 kW and commissioning from 19 July 2012,
2 246 operators opted for remuneration over 10 years and 1 189 operators opted for a one-off payment. Thus around one in three plant operators in the capacity segment < 2 kW claimed the flat-rate one-off payment involving less administrative expenditure.

Moreover, Section 7(1) of the 2012 Cogeneration Act allows operators of small CHPP < 50 kW to opt for surcharges to be paid over ten years or for 30 000 hours' full load operation. Over the period between the entry into force of the Cogeneration Act on 18 July 2012 and 8 September 2014, 8 537 CHPP were classed in the capacity category 'greater than 2 kW up to 50 kW'. Of those plants, 643 (i.e. approx. 7.5 % of CHPP in that capacity segment) received remuneration over 30 000 hours' full load operation rather than over 10 years.

Since July 2012, 162 CHPP with capacity totalling 1.77 MW have been modernised. Modernisation of CHPP (1.54 %) was irrelevant to the overall capacity subsidised in the capacity segment < 50 kW.

Figure 39: Newbuild and modernised CHPP up to 50 kW subsidised under the Cogeneration Act in MW



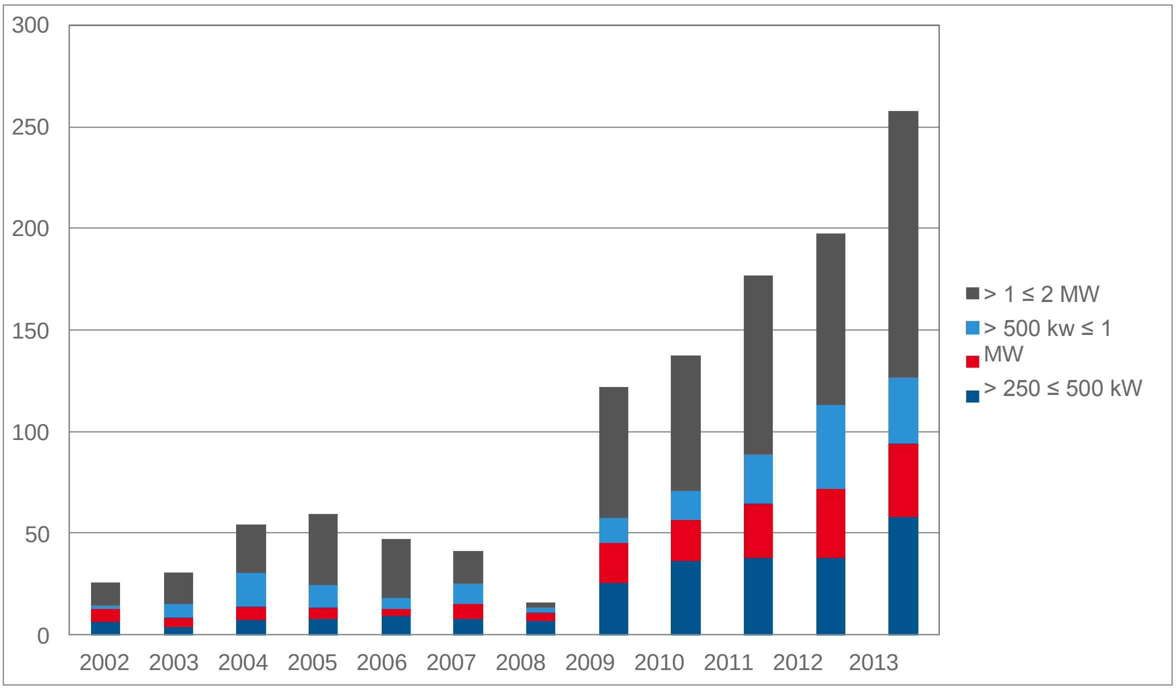
Source: Prognos 2014

In the capacity segment between 50 kW and 2 MW (see Figure 40), the constant increase in subsidised additions and modernisation since 2009 accounted for between 130 MW and 260 MW a year in total. Even this segment clearly benefitted from the 2009 Cogeneration Act Amending Act and the increasing RES levy in subsequent years. The peak was recorded in 2013 (260 MW). The capacity segment between 50 kW and 2 MW was by far the most dynamic compared to the period before 2009.

The top capacity segment between one and two MW was the most strongly represented in the period from 2009 to 2013, with just under 49 % of subsidised capacity, followed by the smallest segment of 50 kW to 250 kW with 22 % of subsidised capacity. The capacity classes between 250 kW and 1 MW accounted for 15 % and 14 % respectively.

Even in the 50 kW to 2 MW segment, modernisation plays a very secondary role. In total, 98 plants with electrical capacity of a good 68 MW have fallen in this category since 2009. They account for approx. 5 % of all subsidised plants between 50 kW and 2 MW.

Figure 40: Newbuild and modernised CHPP between 50 kW and 2 MW subsidised under the Cogeneration Act in MW



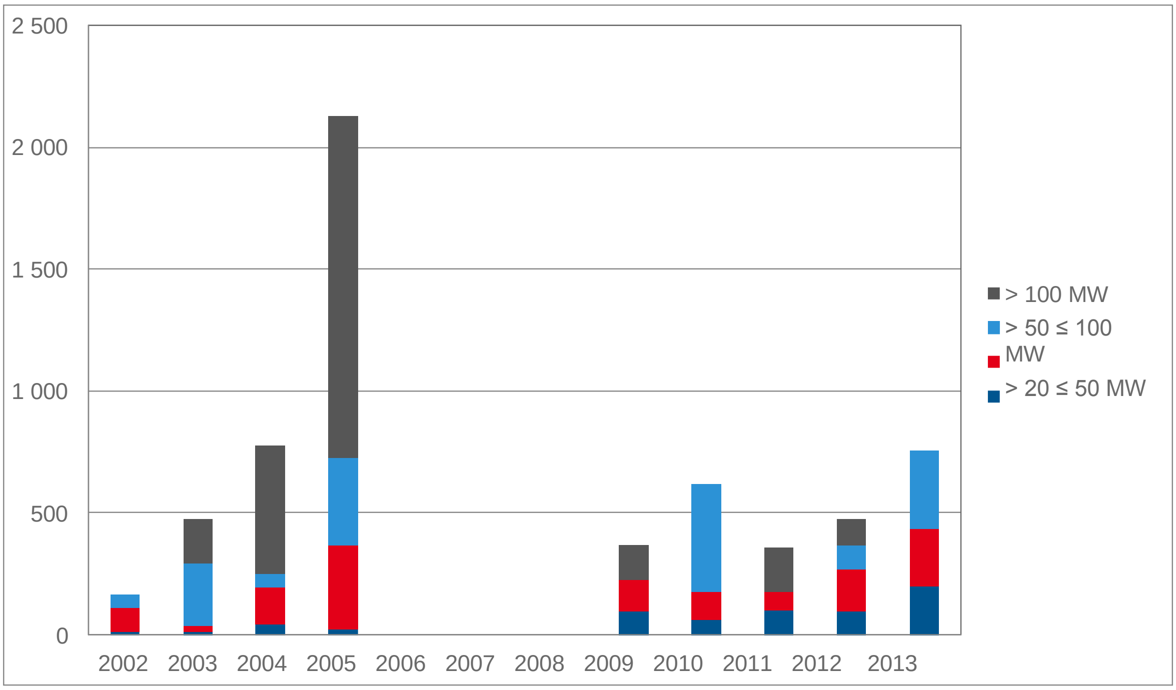
Source: Prognos 2014

The segment over 2 MW accounted for 69 % of modernised or newbuild plant capacity since 2009. Development rates fluctuated between 360 MW and 750 MW. Modernisation accounted for 72 % (542 MW) in 2013; that was the highest value since the 2009 Amending Act. Since 2009, 56 CHPP with an capacity of a good

1 092 MW have been modernised, approx. 70 % (750 MW) since the 2012 Cogeneration Act Amending Act. Annual newbuilds in 2012 and 2013 were 267 MW and 212 MW a year lower than before the 2012 Amending Act (over 330 MW). In total since 2009, 109 new plants with electrical capacity of 1 474 MW have been erected.

The peak in 2005 was due to subsidisation of modernisation measures for plants re-commissioned for continuous operation up to 31 December 2005. In 2006 to 2008 there were no subsidies for newbuilds or new modernisation measures for plants > 2 MW.

Figure 41: Newbuild and modernised CHPP of at least 2 MW subsidised under the Cogeneration Act in MW



Source: Prognos 2014

7.3 Expansion of heat and cooling networks

One important prerequisite in maintaining and expanding cogeneration is to increase heat sales or stabilise them in cases of successful thermal insulation of buildings and processes and the efficient application of heat. Heating networks still offer an opportunity for low-CO_2 heat supply to urban areas in which there is only a limited range of technologies for a low-CO_2 heat supply due to spatial restrictions (solar heat, heat pumps) or air quality aspects (biogenic solid fuels). The development of cooling networks also offers an opportunity for making sensible use of cogenerated heat in coolers, especially in the summer.

In order to stabilise sales, new heating and cooling networks need to be developed and existing networks need to be expanded, as the quantities supplied to date to customers connected to existing heating networks will fall continuously. Construction of heating and cooling networks has been subsidised under the Cogeneration Act since 2009. Up to 2012, the maximum grant was 20 % of the investment.

Under the 2012 Cogeneration Act Amending Act, the maximum possible investment subsidy was increased with retroactive effect to 1 January 2012 a maximum for network expansion of 30 % or 40 % for networks with a nominal diameter of less than 100 mm. Only heating networks in which at least 60 % of the heat delivered is cogenerated or will be cogenerated once the network has been expanded are subsidised.

Under Section 5a(3), second sentence, of the Cogeneration Act, network expansion measures to increase the volume of heat that can be transported by at least 50 % in the section of line concerned are eligible.

Where a steam network is converted to a hot water network during network expansion measures and only the return line is increased, that measure is eligible under the Cogeneration Act. The surcharge is calculated based on the length of the line and the nominal diameter of the return line; proof of eligible investment costs must be provided to that effect. For the rest, the statutory criteria described above apply for the purpose of network expansion subsidies.

According to the AGFW main 2012 report, the connected capacity of hot water networks and steam networks on 31 December 2012 was approx. 47.5 GW and approx. 4.2 GW respectively. Steam networks therefore account for approx. 8 % of total connected capacity. According to the AGFW, network losses in steam networks (13 %) were only slightly higher than losses from hot water networks (12 %).

That slight difference is probably due to the different consumer structure of the two types of network. Most existing steam networks supply a high volume per metre of line, whereas hot water networks include networks with a smaller supply structure.

Due to the higher temperature in steam networks, the steam must be uncoupled at a higher temperature in the CHPP. Thus the electrical efficiency rating of these plants is lower compared to CHPP with hot water networks. Long-term conversion of steam networks to hot water would increase the overall efficiency of cogeneration in district heating.

Changes to subsidised heating and cooling networks in the period from 2009 to 2013 can be presented explicitly based on the data available. For the current year (2014), BAFA is expected to have a slightly lower number of applications, as the application deadline for heating and cooling networks completed in 2014 ended on 1 July 2015. Therefore it is still not possible to draw any conclusions for 2014. The evaluation as at July 2014 has been presented.

No applications have been received to date for subsidies for cooling networks; hence the evaluations below refer solely to heating networks.

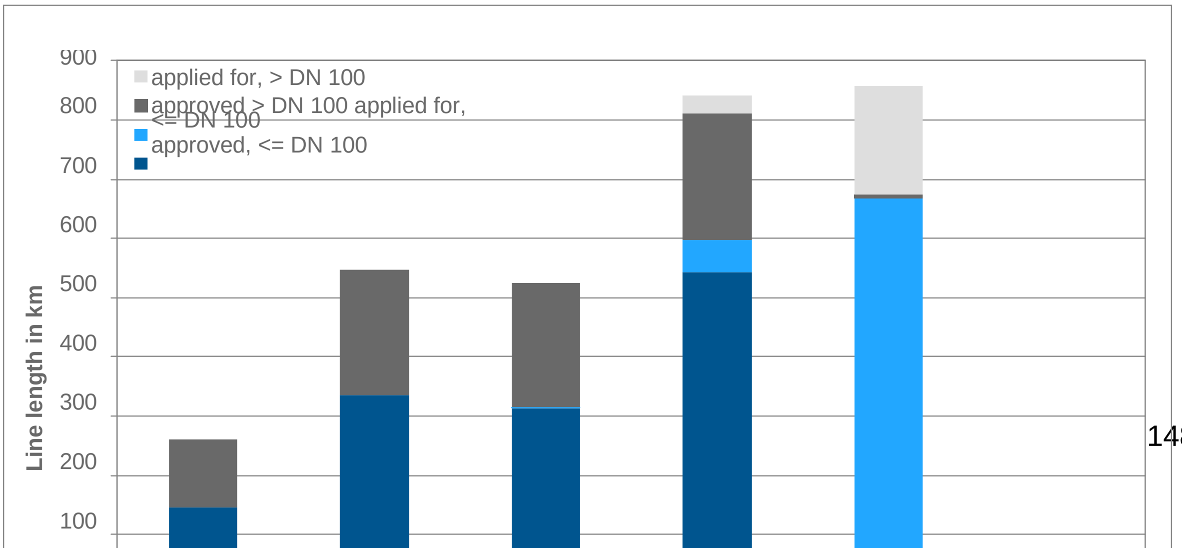
In 2010 and 2011, subsidised network development totalled 548 and 525 km respectively. In 2012 and 2013, that rose to 841 and 857 km respectively. It should be noted that the overwhelming majority of networks which applied for subsidies are still at the authorisation stage (Figure 42). As Figure 42 also illustrates, just under one-third of the length of lines for which subsidies were approved or applied for had an average diameter greater than 100 mm per district heating project; a good two-thirds were less than 100 mm.

The spike in the length of lines with a nominal diameter < 100 mm for which subsidies were applied for and approved indicates that, due to the improved subsidy scheme under the 2012 Cogeneration Act, more investments were made in network consolidation and developing small heating networks.

However, the rising number of subsidised district heating networks with biogas-fired CHPP is not necessarily due to a stronger increase in the use of heat from biogas-fired CHPP. It may also be due to the fact that the efforts identified during monitoring of the 2009 Cogeneration Act to have district heating networks in the biogenic sector subsidised under the Development Loan Corporation 'Premium' RES scheme no longer apply to the same degree following the adjustments made to both subsidy systems.

BAFA has issued a total of two approvals for conversion from steam heating to hot water networks since 2014.

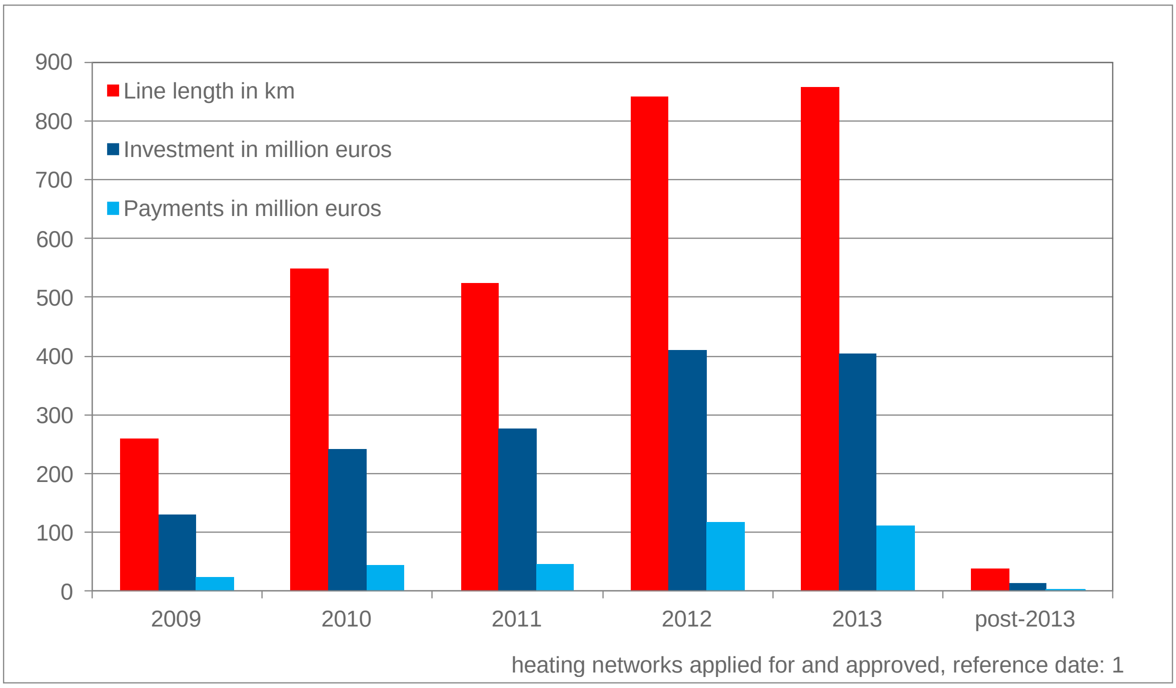
Figure 42: Line lengths of networks for which subsidies have been approved or applied for by year of commissioning and nominal diameter in km



Source: Prognos 2014

The mean subsidy in 2009 to 2011 remained highly stable at around 18 %. Following the increase to surcharges for heating networks under the 2012 Cogeneration Act Amending Act, it rose to just under 29 % (see Figure 43).

Figure 43: Heating networks subsidised under the Cogeneration Act, investment costs and payments made under the Cogeneration Act in million euros



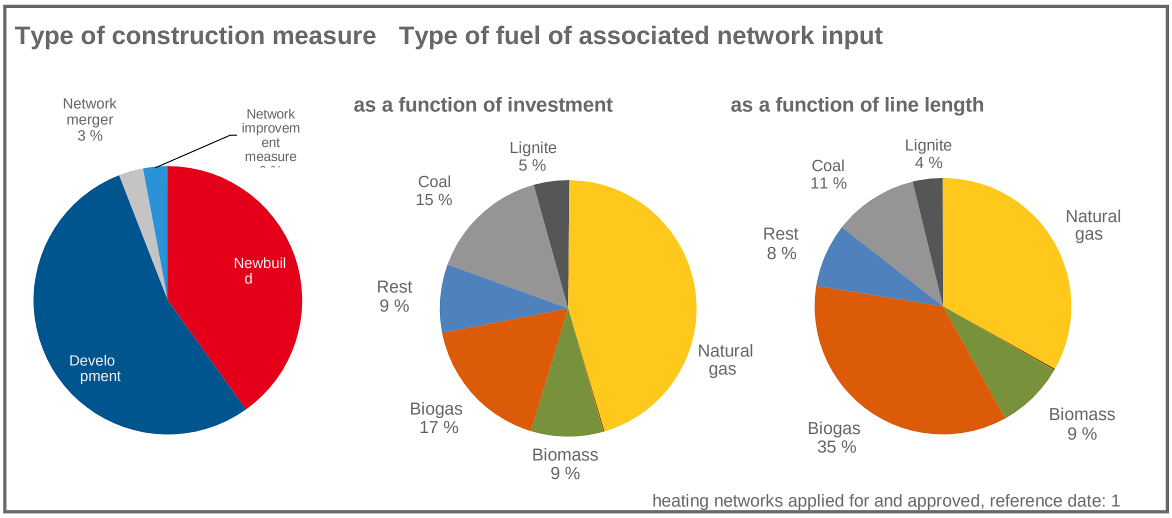
Source: Prognos 2014

In the period from 2009 to 2013, most investments (54 %) were to expand existing networks or parts of networks and 40 % of network investments were to develop new networks. Network improvement measures and measures to merge existing networks accounted for 3 % of the costs. Most investments (45 %) were in networks supplied solely or primarily by natural gas-fired plants; biogas and coal accounted for
17 % and 15 % respectively (see Figure 44). As a function of line length installed, the situation is different: the proportion of networks

supplied by biogas-fired plants is twice as high (32 %).
This is due to the smaller average line diameter or lower specific line costs in this segment, which in turn depends on the smaller number of heat customers connected and the often cheaper underground laying costs in rural areas.

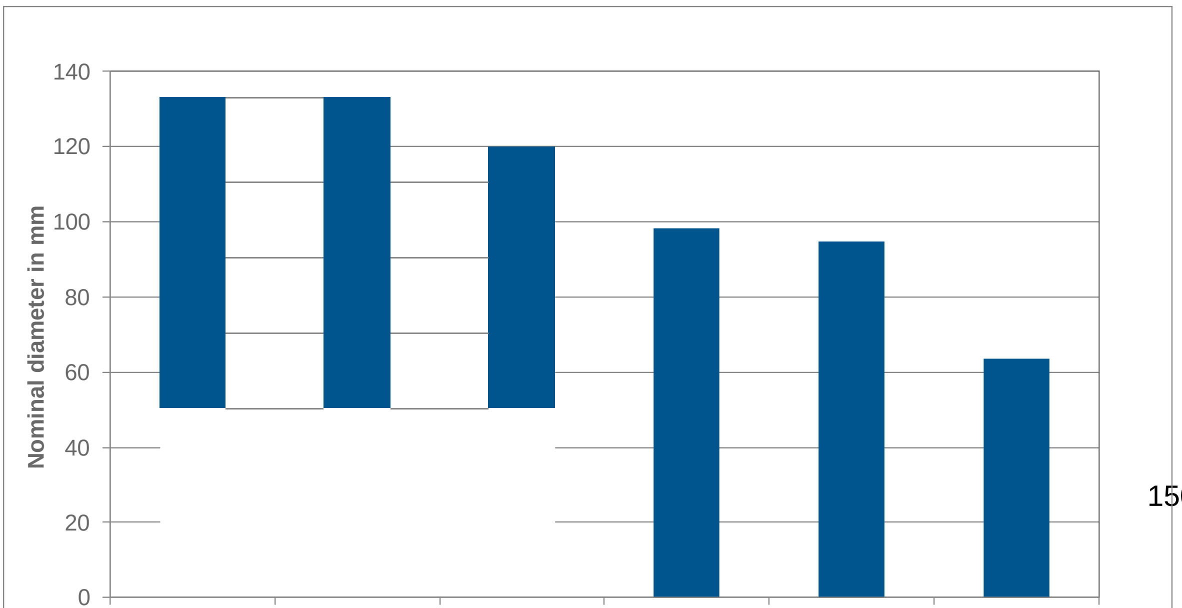
The evaluation of the mean diameter of lines as a function of the energy source (Figure 45) confirms that situation. Heating networks subsidised and applied for that are supplied by biogas-fired plants have by far the smallest nominal diameter (60 mm on average). The mean diameter of heating networks supplied by natural gas- or coal-fired plants is almost twice as big (120 mm). BAFA data on subsidies also illustrate that networks with a diameter > 200 mm are supplied almost solely by fossil fuel-fired plants.

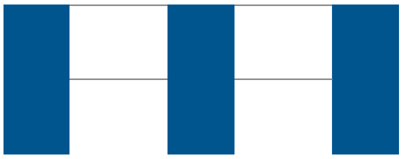
Figure 44: Type of construction measure and network input by energy source of heating networks subsidised/applied for 2009 to 2013



Source: Prognos 2014

Figure 45: Mean diameter of heating networks as a function of energy source of network input in mm

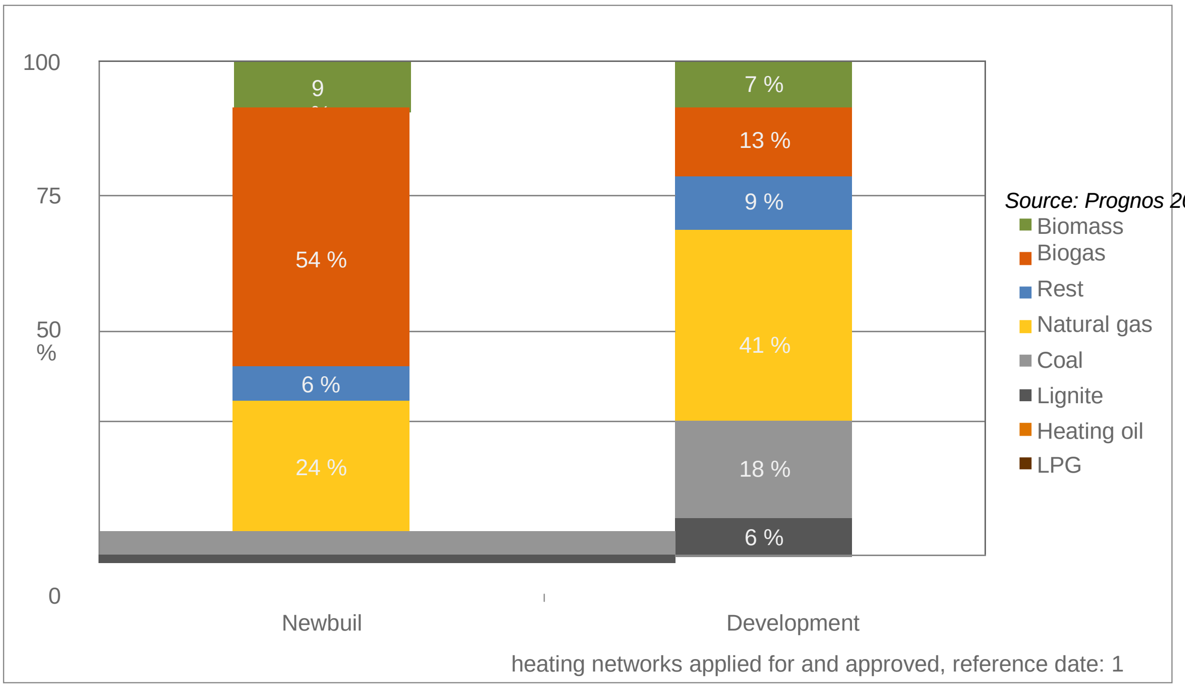




Source: Prognos 2014

There are also clear differences in the distribution of heat input for newbuild and development projects (Figure 46). Whereas 63 % of the line length of newbuild projects are supplied by biogenic fuel-fired plants (solid biomass and biogas), that figure is much lower for network development projects (20 %). Here natural gas dominates (41 %), followed by coal (18 %). The BAFA data also illustrate that newbuild networks have a much smaller mean diameter (87 mm) than expanded networks (104 mm).

Figure 46: Distribution of energy sources of heat input for newbuild and expansion projects (percentage) in relation to line length



Source: Prognos 2014

7.4 Additional heat/cooling storage facilities

The advantage of CHPP is that they efficiently couple power and heat production with less fuel and CO_2 emissions than uncoupled production. However, they have limited flexibility in power production, as they have to base that beneficial cogeneration operation primarily on the heating requirement connected. The cogenerated heat produced can also be used to operate central or decentralised cooling plants or cooling networks. That being so, the effects of the construction of thermal heat storage facilities described below basically apply to heat and cooling storage facilities.

Plant engineering which connects thermal storage facilities electricity market-driven CHPP can contribute enormously to more flexible power generation by CHPP. It allows cogenerated power production to be uncoupled at times from heating and cooling requirements. Thermal storage facilities can store cogenerated heat for several hours or days at times of low heat/cooling and high power demands and then deliver them at times of low power and high heat/cooling demand. With the increasing development of RES and associated times of low residual load, this can also prevent cogenerated power production, which makes sense *per se*, does not cause a reduction or down-regulation of fluctuating renewable (PV or wind energy) power production.

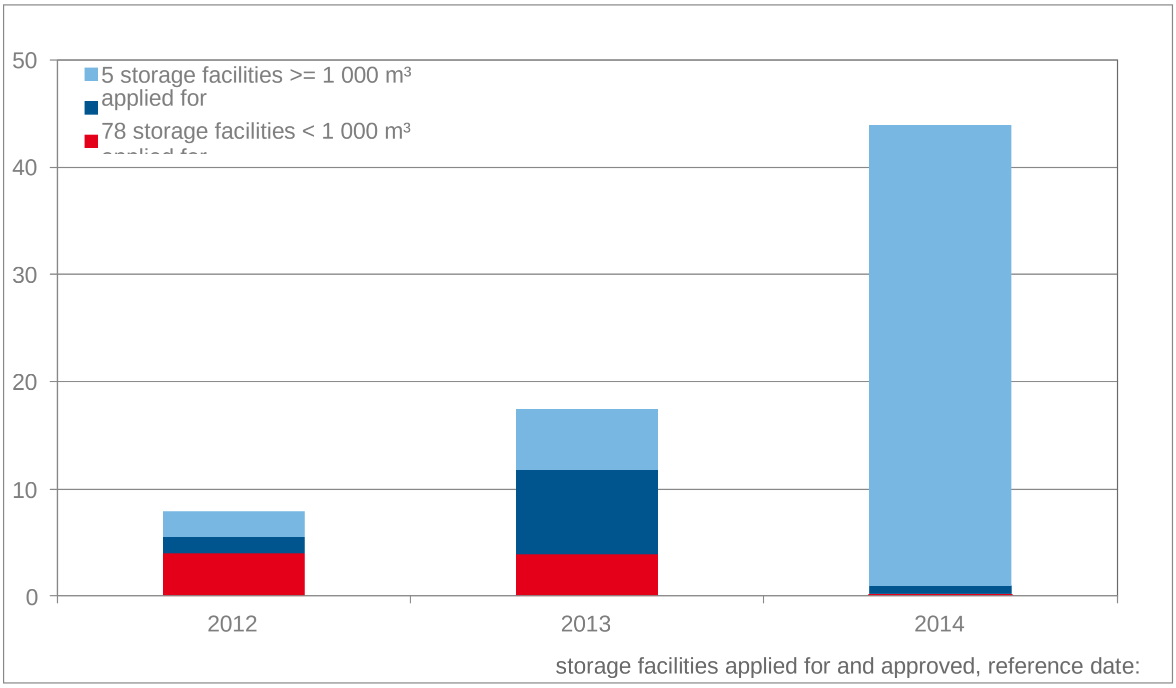
Heat storage facilities can already help in the short term and will help increasingly in the medium to long term to make sensible use of surplus power produced from RES: the installation of electric heaters in heat storage facilities means that it is already technically possible in the short term to supply negative control energy and thus help to stabilise the power system, especially in supply areas with network overload. In the medium to long term, these electric heaters will also enable decentralised use of surplus power and thus limit network expansion or the installation of much more expensive storage systems. The economic prerequisite to that would, however, be a marked reduction in duty, taxes and fees for power purchased by heat storage facilities. The positive impact of the combination of heat storage facilities and electric heaters on the power system was recently substantiated in the study entitled 'Measures for the sustainable integration of systems for coupled power and heat supply in the new energy supply system'.

The 2012 Cogeneration Act Amending Act introduced subsidies for heat and cooling storage facilities in the form of an investment subsidy under the Cogeneration Act. That subsidy is currently a one-off payment of EUR 250 per cubic metre water-equivalent storage volume for smaller storage facilities (up to a maximum of 50 cubic metres). For larger storage facilities, the subsidy is also capped at 30 % of the eligible investment costs and EUR 5 million per project.

Since that subsidy was introduced in 2012, 89 storage projects with a total storage capacity of approx. 8.100 m³ have been completed and paid an investment subsidy according to BAFA statistics. The size of these subsidised heat storage facilities ranges from 1 m³ to a maximum of
2 350 m³. Cooling storage facilities have been less relevant to date.

A further 81 heat storage facilities with a capacity of approx. 53 000 m³ are still in the approval procedure. The investments in these storage facilities total EUR 27.6 million. Most of the storage volume applied for (43 000 m³) is accounted for by the heat storage facilities of GKM in Mannheim (Figure 47).

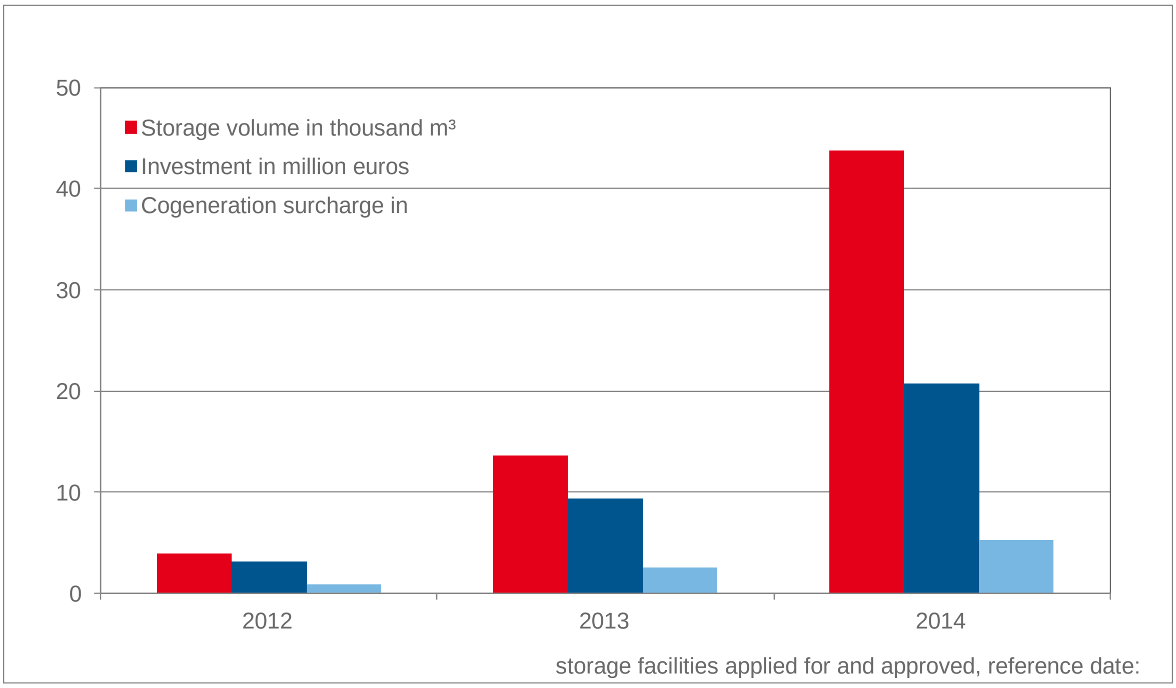
Figure 47: Volumes of heat storage facilities for which subsidies have been approved or applied for by year of commissioning in thousand m³ of storage volume



Source: Prognos 2014

The investment costs for storage facilities already approved totalled approx. EUR 5.5 million, of which approx. EUR 1.5 million was paid in grants. The average subsidy rate for these projects was therefore approx. 27.5 % (see Figure 48).

Figure 48: Heat storage facilities subsidised under the Cogeneration Act, investment costs and payments made under the Cogeneration Act



Source: Prognos 2014

Several more heat storage facilities are also being planned or built at present. The following table gives an overview of larger heat storage projects currently being implemented. This list makes no claim to being complete, but it does illustrate that, in the meantime, much larger projects are being implemented. These 15 heat storage facilities or heat storage projects alone, disregarding the storage facility in Mannheim, have a storage volume totalling 230 000 m³.

Re classification of these projects: In the study entitled 'Measures for the sustainable integration of systems for coupled power and heat supply in the new energy supply system' [Prognos 2013], Prognos estimated that heat storage capacity of 200 GWh was needed in the long term (up to 2050). In order to provide that storage capacity, storage volume of approx. 4 million is needed in the case of unpressurised heat storage facilities. The storage projects listed here therefore already represent a considerable proportion of the heat storage facilities needed in the long term for flexible cogeneration.

Table 48: Other heat storage projects in Germany (list may be incomplete)

Undertaking	**Town**	**Volume in m³**	**Electric heaters**	**Commissioned**	**Status**
Stadtwerke Duisburg	Duisburg	46 000			Planned

Potsdam Energie und Wasser	Potsdam	45 800	Yes	2015	Planned
MVV Energie, Großkraftwerk Mannheim AG	Mannheim	43 000		2013	In operation
N-ERGIE AG	Nuremberg	33 000	Yes	2015	Under
Stadtwerke Kiel	Kiel	30 000	Yes		Contract put out to
Stadtwerke Flensburg	Flensburg	29 000	Yes		In operation
DVV Dessau GmbH	Dessau	20 000	Yes	2015	Planned
Fernheizwerk Neukölln AG	Berlin	10 000	Yes	2014	Planned
Stadtwerke Erfurt	Erfurt	7 000		2014	Under
Stadtwerke Leipzig	Leipzig	3 000		2014	Under
Heizkraftwerk GmbH Mainz	Mainz	3 000	Yes		
Gemeindewerke Grosskrotzenburg	Grosskrotze nburg	2 500		2015	Approved
Stadtwerke Hennigsdorf, BombardierTransportation	Hennigsdorf	250		2014	In operation
Stadtwerke Ludwigsburg-Kornwestheim	Ludwigsburg	250		2014	In operation
Stadtwerke Lübeck	Lübeck	150		2014	Under

Quelle: Prognos research, Prognos 2014

There are also plans and planning applications for a further three very large heat storage facilities in Hamburg and Berlin. However, they have been stopped for the time being for financial reasons.

7.5 Economic viability of CHPP

This chapter describes the methodology, underlying assumptions and results of the **economic viability** calculations for CHPP.

The economic viability of **existing plants** has been considered based on a **contribution margin calculation**. That involved determining the annual revenue of the plants and deducting their annual costs. If operation results in positive contribution markets (DB 2) over the year, the existing plant is economically viable.

For **newbuilds**, economically viable operation is a basic precondition, but does not suffice as the sole criterion. Investment in a new plant is also compared to an alternative investment. In other words, the **rate of return on the project** and the **amortisation period** of a newbuild are decisive factors.

The plants are subdivided for the purpose of investigation into public supply plants (district heating cogeneration) and property and industry cogeneration. The criterion for that is the size (installed capacity) of the plant. In both sectors, we considered existing plants for the period from 2008 to 2013 and newbuild projects (commissioned in 2014).

7.5.1 Public cogeneration

Power plants which deliver to the public district heating supply market their electricity on the exchange. We assumed for the purpose of our investigation that they deliver all the power produced to the network. The power plants are used depending on price signals on the electricity market: if the hourly electricity price is higher than the plant's marginal costs, the plant is operated. If there is a simultaneous heat requirement in that hour, heat in cogeneration operation is also uncoupled. In that case, the plant generates additional revenue from sales of power and revenue from sales of heat, both of which are included in the contribution margin calculation.

The economically viable operating hours for individual district heat CHPP are determined by making an hourly comparison between running costs and potential revenue. These are the hours in which the (possibly subsidised) revenue of a plant exceeds its marginal costs (fuel, CO_2 and variable costs). This surplus revenue determined based on running hours is added together over the year to give **contribution margin 1** (DB 1). So that the different sized plants can be compared better, the next step is to standardise the DB1 of each plant based on its installed capacity to give a specific contribution margin per kW installed capacity.

The contribution margin calculation does not map possible **negative contribution margins** which may arise during '**must run**' operation of a CHPP. 'Must run' operation of a CHPP may occur in practice when the revenue from sales of power and heat from operation of the CHPP are too low to cover running costs, but cogeneration is necessary in order to meet the demand for heat. This may happen in district heating systems with several CHPP if the uncoupled peak load boiler is not sized to cover the entire demand for heat. In such systems, in which several CHPP back up each other's heat production, the contribution margins (annual totals) may be lower in reality than in the calculations presented below.

Contribution margin 2 (DB 2) is calculated based on DB 1, by deducting fixed operating costs (staff, maintenance etc.) from DB 1. If these calculations give positive values for DB 2, that indicates that depreciated plants can be operated economically, as all costs are covered. Thus DB 2 is the basis on which a decision is taken as to whether a plant can be operated economically or cannot and is then shut down. Operators of depreciated plants with a positive DB 2 generate a surplus from operating the plant; however, specific profit expectations are disregarded in this investigation. Like DB 1, DB 2 is standardised based on the installed electrical capacity of the plant and reported as a specific annual value.

For **newbuild plants**, the **rate of return on projects** and the

amortisation period of the investment are decisive factors. Aside from the difference between annual costs and revenue (cash flow), the costs of the initial investment are also included in the calculations. The annual cash flow is equal to DB 2.

The **rate of return on projects** is calculated using the internal interest rate method. The arithmetical interest rate at which total annual discounted cash flow (including initial investment), i.e. the net present value, is zero is calculated based on that total. A negative rate of return on a project is reason not to make the investment; if the rate of return is positive, it is compared with the anticipated rate of return on a comparable investment. In the past, new plants were generally built if the rate of return on the project, understood as the overall rate of return, reached a nominal value of around 10 % (equivalent to approx. 8 % in real terms). The operator's return on equity could be higher if a soft loan (i.e. at a rate of interest of less than 10 %) were included in the project financing.

The **static amortisation period** is the period over which an investment pays for itself without expectation of any yield. It is calculated by dividing the initial investment by the mean annual cash flow. This parameter is applied primarily to short-term refinancing investments over a period of a few years in which the ROCE is of secondary importance.

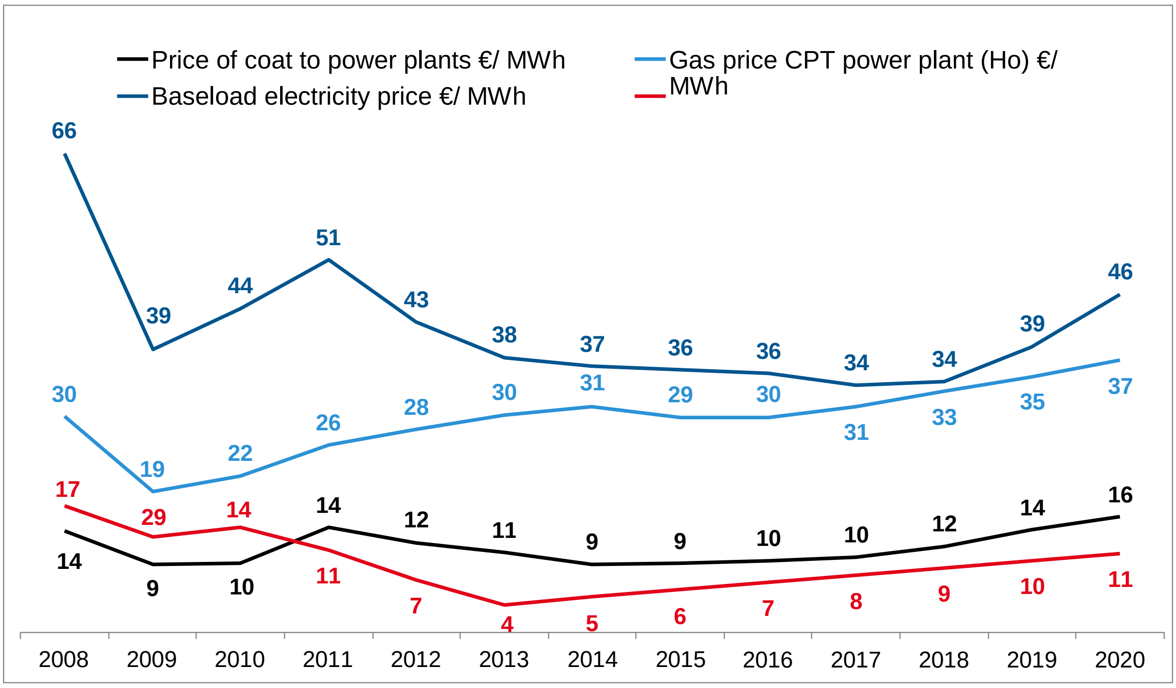
The basic data and assumptions used to calculate the economic viability of public CHPP are explained below.

Fuel and CO_2 prices

Fuel and CO_2 costs account for a large portion of variable running costs (marginal costs) and therefore have a large influence on the economic viability of the plant. Changes since 2008 and forecasts for the immediate future are illustrated in Figure 49 in nominal prices. Assumptions on longer-term changes are based on the energy reference prognosis (see Table 7) and are presented as a trend extrapolation up to 2035 in Table 49.

Figure 49: Fuel and energy prices 2008-2020, nominal

Source: EEX 2014, Prognos 2014



Changes over coming years can be predicted from the futures already being traded, which are input into the prognosis for short-term energy prices up to 2020. They reflect anticipated electricity prices, which are marked by stagnating demand for energy and a power plant inventory with excess capacity. The prices of all energy sources collapsed in the 2009 economic crisis and recovered in subsequent years up to 2011. After 2011, the prices of electricity and coal dropped again; only the price of power station gas maintained its upward trend. The price of CO_2 certificates declined up to 2013 to EUR 4/t and is doing little to drive the change to low-emission energy sources/technologies. Only a gradual increase to EUR 11/t nominal is expected over coming years up to 2020. Electricity and gas prices are expected to converge sharply up to 2018, which will exacerbate the economic situation of gas-fired power plants. The energy prices illustrated in Figure 49 break down as follows:

The '**gas price CPT power plant**' includes the purchase price, i.e. the pure gas price that power plant operators pay for gas, together with transportation fees and fees for structuring gas deliveries. For the purchase price, the calculations below for the period up to 2011 assume long-term supply contracts whose mean price levels reflect the cross-border price for natural gas. Those long-term contracts are slowly expiring and gas is increasingly traded and purchased at spot prices. Therefore, from 2011 onwards, the gas price CPT power plant is based on purchases at spot prices on the spot market. A price of 5 Euro$_{2013}$/MWh has been assumed for transportation and structuring fees.

From 2009 to 2011, gas prices on the **spot market** were affected by the after-effects of the economic crisis and a surplus supply of gas in Germany and were relatively low (19 to 26 Euro$_{2013}$ /MWh. In 2013, they attained a level of 30 Euro$_{2013}$ /MWh, which is taken as constant over the next few years. Further moderate increases are not expected under after 2018.

These gas prices do not include **any natural gas tax**, as **CHPP** are exempt from natural gas tax. We have assumed that that exemption will be maintained over the period considered.

In order to calculate the revenue from sales of heat based on alternative **production in a peak load boiler**, natural gas tax of 5.5 Euro$_{2013}$ /MWh was taken into account. The changes in that ‘gas price for peak load boilers’ mirror the changes in the gas price CPT power plant and are also shown in Table 49.

The ‘**coal price CPT power plant**’ tracks changes in international coal prices and, for Germany, is only affected by changes in the EUR/USD exchange rate. The power plant supply prices are based on the cross-border prices for coal in Germany and transportation fees. Due to the large supply of coal on the global market, prices have fallen since 2008 and, once they have bottomed out, are expected to remain stable in the long term up to 2020.

Table 49: Fuel and CO_2 certificate prices, prognosis

		2014	2015	2020	2025	2030	2035
Gas price CPT power plant (Ho)	€$_{2013}$/MWh	31	29	35	35	36	37
Gas price for peak load boiler (Hu)	€$_{2013}$/MWh	36	34	40	41	41	42
Coal price CPT power plant	€$_{2013}$/MWh	9	9	14	15	16	16
CO_2 certificate price	€$_{2013}$/t	5	7	10	26	42	55
Phelix base load	€$_{2013}$/MWh	36	35	42	55	67	75

Source: Prognos/EWI/GWS 2014, Prognos

CO_2 certificate prices have fallen sharply since 2008; in 2014 they were 5 Euro$_{2013}$/t CO_2. No shortage and hence higher certificate prices are anticipated up to 2020. Only in the medium term are climate protection measures stepped up in this scenario, resulting in more intensive emissions trading which will cause an increase to 55 Euro$_{2013}$/t CO_2 by 2035.

Revenue from sales of electricity

The main parameter on the revenue side is the **price of electricity**, which is affected by fuel and CO_2 certificate prices, on the one hand, and the development of RES, on the other. The hourly electricity price also provides the signal for the use of CHPP. Past average wholesale electricity prices (Phelix base load) are shown in Figure 49. Wholesale electricity prices collapsed due to the economic crisis, with falling fuel prices and reduced demand for electricity. Prices gradually increased with the economic recovery from 2010 onwards.

They fell again in 2013 due to lower CO_2 certificate prices and the merit order effect of RES. Expected future changes in electricity prices track the energy reference prognosis up to 2030 and the trend scenario thereafter (Prognos 2014). Electricity prices fall over the years up to 2020, due to excess capacity, low CO_2 prices and further development of RES. After 2020, rising CO_2 certificate prices and a shortage of generating capacity give rise to higher electricity prices, which rise to 67 $Euro_{2013}$/MWh by 2030 and to 75 $Euro_{2013}$/MWh by 2035.

The hourly electricity prices input into the economic viability calculation are based on these annual averages. The Prognos power plant model was used for this calculation.

Revenue from sales of heat

Revenue from sales of heat is estimated based on a mixed calculation of upper and lower revenue from sales of heat. Upper revenue comprises the costs of an alternative heat supply in a natural gas-fired peak load boiler. That applies where the CHPP crowds out heat production from a gas-fired peak load boiler. For the peak load boiler, an efficiency rating of 90 % and the natural gas price in that year including natural gas tax of 5.50 $Euro_{2013}$/MWh is assumed. Lower revenue is estimated as the opportunity costs of heat production in a CHPP. They comprise the revenue lost on the power side due to heat uncoupling. Heat uncoupling reduces power production and associated sales of electricity. The calculations are based on a power loss index of 15 % and loss of revenue from sales of power equal to the annual mean for base load at the time.

In most district heating systems in Germany, several CHPP and peak load boilers deliver to the connected heating network. This is especially true for the large heating networks (e.g. Berlin, Hamburg, Ruhrschiene, Saarschiene, Hannover, Frankfurt, Leipzig etc.). Construction of a new or shutdown of an existing CHPP replaces or requires either cogeneration or peak load heat in hourly heat production. The ratios may vary considerably from case to case, depending on the network and production structure. In this study, an annual mean of half is assumed.

The mean values listed in Table 50 and Table 51 are obtained from the upper and lower revenue from sales of heat. They are 23 $Euro_{2013}$/MWh in 2014 and rise to 29 $Euro_{2013}$/MWh by 2035. That increase is triggered over that period by rising gas and electricity prices.

Table 50: Revenue from sales of heat used to calculate economic viability of district heating CHPP 2008-2013

		2008	2009	2010	2011	2012	2013
Competitive revenue from sales of heat	€$_{2013}$/MWh	26	18	19	22	23	23

Source: Prognos 2014

Table 51: Revenue from sales of heat used to calculate economic viability of district heating CHPP, prognosis

		2014	2015	2020	2025	2030	2035
Competitive revenue from sales of heat	€2013/MWh	23	22	26	27	28	29

Source: Prognos 2014

CHPP in emissions trading

In the period after 2008, operators of CHPP installed in a property supplied with installed combustion heat capacity of over 20 MW were obliged to participate in emissions trading. From 2008 to 2012 (second emissions trading period), CHPP were allocated free certificates for the power produced and the heat produced. They depended on the fuel used. For electricity, the benchmark was 750 g CO_2/kWh for coal and 365 g CO_2/kWh for gas. The heat benchmark was 345 g CO_2/kWh for coal and 225 g CO_2/kWh for gas. Thus plant operators sometimes received an over-allocation of certificates.

From 2013 (third emissions trading period), all emissions for power production are auctioned; for heat production, free certificates are again allocated. However, the heat benchmark for allocation falls again to zero g CO_2/kWh by 2027, as illustrated in Table 52. From 2027 onwards, cogenerated heat production is also fully subject to emissions trading. The free allocation of certificates is also taken into account in the economic viability calculation.

Table 52: Heat benchmark for free allocation CO_2 certificates

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Heat benchmark (g CO_2/kWh)	176	158	140	122	105	89	73	58	49	40	31	23	15	7	0

Source: Öko-Institut, IZES, Ziesing 2014 based on EU ETS Directive 2009/29/EC

Cogeneration remuneration

The economic viability of plants is considered with and without subsidisation. In the event of subsidisation, the cogeneration surcharge is paid per kWh of cogenerated electricity delivered. That reduces the marginal costs of the plant in hours in which the plant operates in cogeneration mode and increases the number of hours in which the plant can be used. The calculation is made for the past (2008 to 2013) using the remuneration rates applicable in each year (see Table 53); for the prognosis, the current surcharge rates laid down in the 2012 Cogeneration Act are extrapolated (see also Table 8). For CHPP with installed electrical capacity > 2 MW which participate in emissions trading and which went into permanent operation on or after 1 January 2013, the surcharge rises by 0.3 Cent/kWh.

Table 53: Cogeneration Act surcharge rates, nominal

	By capacity		2008	2009	2010	2011	2012	2013	2014
New existing plants		Cent/kWh	0.82	0.56					
Modernised existing plants		Cent/kWh	1.64	1.59	1.59				
CHPP > 2 MW	< 50 kW	Cent/kWh		5.11	5.11	5.11	5.41	5.41	5.41
	50 kW to 2 MW	Cent/kWh		2.10	2.10	2.10	4.00	4.00	4.00
	2 to 10 MW	Cent/kWh		2.10	2.10	2.10	2.40	2.40	2.40
	> 10 MW	Cent/kWh		1.50	1.50	1.50	1.80	1.80	1.80

Source: 2009 Cogeneration Act, 2012 Cogeneration Act,
for plants in emissions trading, the surcharge rises by 0.3 Cent/kWh as of 1 January 2013

Network user fees saved and costs per start-up process

Network costs are avoided for deliveries to a lower network level than the high voltage level. These are refunded to plant operators by transmission system operators. The amount of network user fees saved depends on the transmission system operator and comprises a work portion and an capacity portion.

Start-up processes in the power plant generate additional costs. They depend on the size and type of plant (see Table 9 in Chapter 4.1) and are taken into account in the annual costs. The estimated amount is determined based on information from the operators.

Revenue from control energy

Aside from revenue from sales of power and heat and saved network user fees, the control energy market represents an additional source of revenue for some CHPP. In theory, CHPP can supply all types of control energy subject to appropriate prequalification.

According to the Federal Network Agency and Federal Cartel Office monitoring report [BNetzA 2014] the control energy market was worth EUR 416 million in 2012, of which EUR 82 million for primary regulation, EUR 267 million for secondary reserves and EUR 67 million for minute reserves. At present, most control energy is provided by fossil fuel-fired power stations (with and without cogeneration), hydroelectric power stations and pumped-storage power plants. Industrial (load management) undertakings and electric heaters also provide control energy. The proportion of control energy offered and supplied by CHPP was not investigated in detail or estimated in this study.

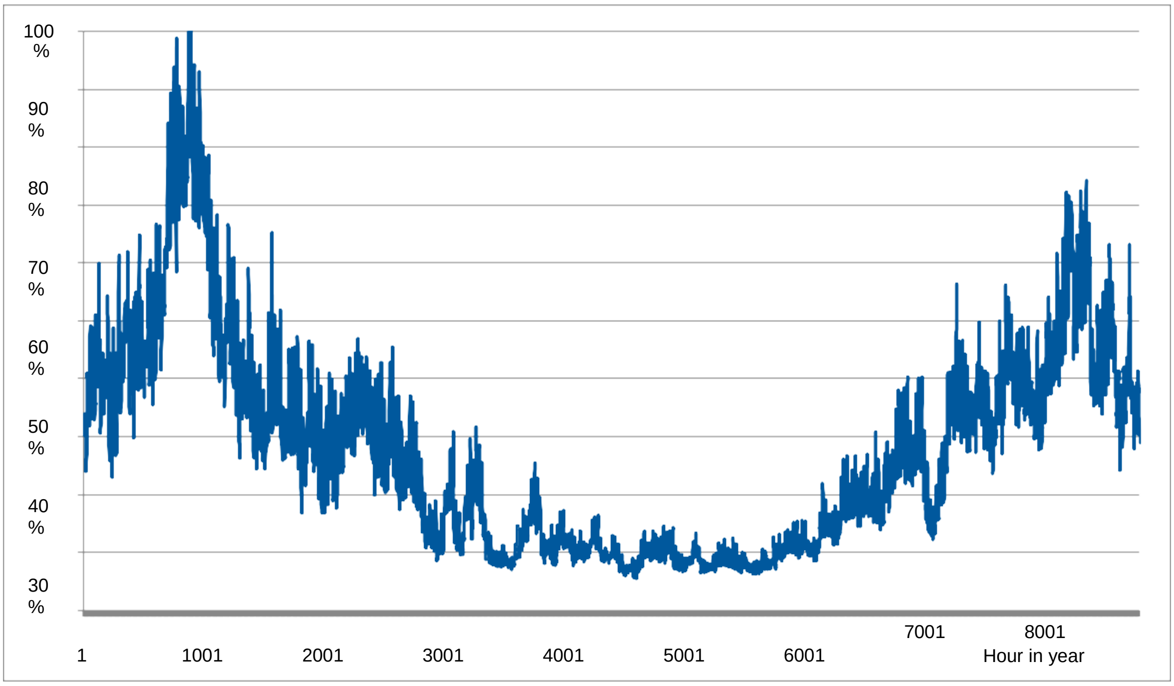
CHPP, especially flexible plants in the public district heating supply system can also generate additional revenue on this market. However, the control energy market was disregarded when calculating the economic viability of CHPP, as the additional revenue for the various types of plants cannot be reliably estimated. The potential revenue depends enormously on the individual situation of each CHPP or the undertaking which operates it and optimal use thereof. Compared to revenue from sales of power and heat, the control energy market is of very secondary importance.

Heat load profile

The use of CHPP is modelled on an hourly basis. It depends on the hourly demand for heat of connected customers, on the one hand, and the electricity prices that can be obtained, on the other. In cogeneration mode, additional revenue from heat of sales is taken into account, compared to uncoupled power production, and (optionally) the cogeneration surcharge. Hourly modelling of the demand for heat is based on a typical heat load profile (see Figure 50), which is based in turn on the supply data of a German municipal utility company.

CHPP do not cover the demand for district heating in full in practice; the heat load profile described must therefore be adjusted for the calculations. In many district heating networks, there is a base load delivery of waste heat from refuse incineration or industrial plants. Furthermore, most CHPP are not designed for the maximum demand for heat, as that capacity is required only very rarely. In order to guarantee an uninterrupted supply with district heating, the maximum load is generally secured using additional peak load boilers. Peak load boilers are used if the electricity prices in individual hours are too low to operate the CHPP at breakeven point despite the existing heat requirement.

Figure 50: Heat load profile



Source: Prognos 2014 based on information from a municipal utility company operator

In order to model cogeneration use, the heat load profile described is therefore modified to reflect the aforementioned restrictions, in order to map as true a picture of the use of CHPP as possible. On the one hand, this is done by setting a cap on the heat load that can be covered by CHPP. On the other hand, the base load delivery is deducted from the heat profile. If and to what extent (%) plants are used in cogeneration mode depends on the modified hourly heat load in the model. It is assumed that the peak load boilers are sufficiently sized to prevent must-run operation of the CHPP (see above.

Types of district heating CHPP investigated

The economic viability analysis of district heating CHPP has been carried out for five gas-fired power plants and two coal-fired power plants (see Table 54), the parameters of which are detailed in Table 9. They range from 10 MW to 800 MW and therefore cover a broad range of plants and are currently in operation in this plant configuration. Apart from 'Coal 1', which is a depreciated, older coal-fired power plant, these plants can also be erected as newbuilds.

Table 54: Additional information on CHPP

		BHPP 6	G&S 1	G&S 2	G&S 3	G&S 4	Coal 1	Coal 2
Capacity	kW_{el}	10 000	20 000	100 000	200 000	450 000	400 000	800 000
Fuel		Natural					Coal	
Emission factor	kg CO_2/MWh	200					340	
Start-up costs	$€_{2013}/MW_{el}$	20	40	40	40	40	80	80

Source: IFAM, BHKW-Consult, IREES, Prognos

Results

Based on the aforementioned assumptions, the economic viability calculations give the specific contribution margins given in the figures below for the individual types of plant. Table 88 to Table 93 in the annex detail the results for contribution margins 1 and 2 and the economically viable full load hours of the plants for the period considered (2008 to 2035).

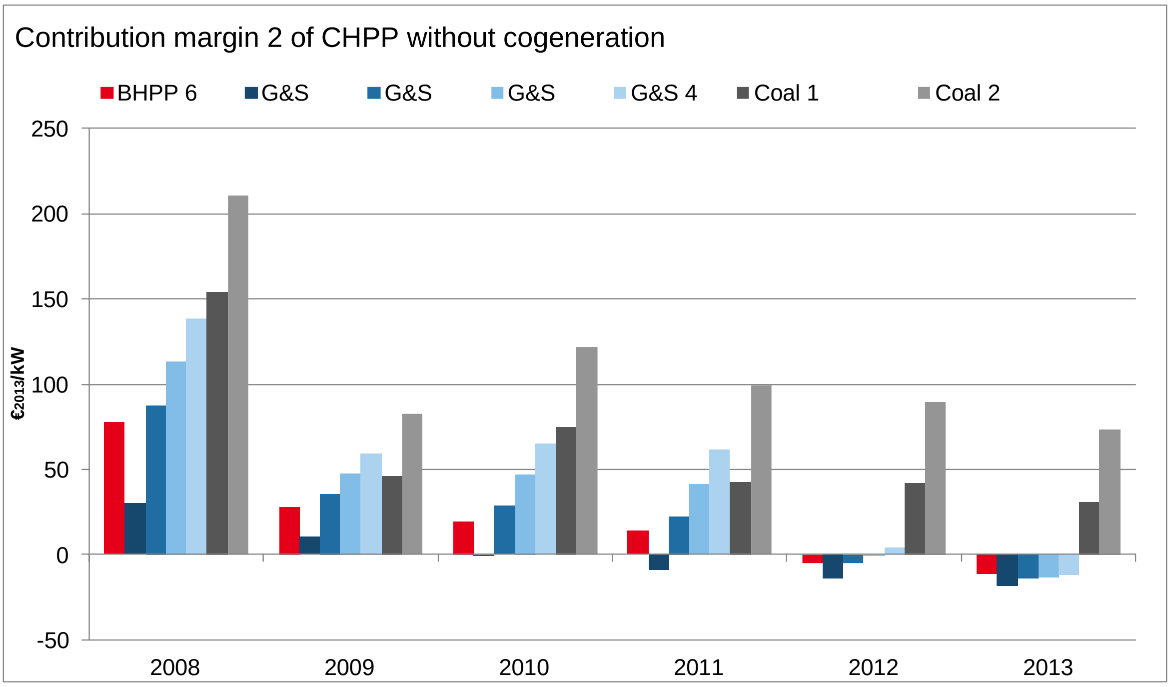
2008 to 2013

In 2013 7.7 TWh of cogenerated power production in plants with installed electrical capacity > 2 MW were subsidised under the Cogeneration Act [Cogeneration Medium-Term Prognosis 2014]. This electricity is divided between industrial plants and public supply plants. Power production by general supply CHPP (just under 50 TWh) was much higher in 2013 than the quantity of subsidised power. Thus most plants were not subsidised under the Cogeneration Act in 2013.

Figure 51 below illustrates the changes to the specific **contribution**

margin 2 for existing plants without cogeneration subsidy in 2008 to 2013: Between 2008 and 2010, all plants achieved a positive contribution margin 2.
The main reason for the high contribution margins in 2008 was that electricity prices were still high then and the plants were able to achieve high revenue on the electricity market. Although electricity prices plummeted in 2009, fuel and CO_2 prices also fell, meaning that plants had lower costs. With gas prices rising from 2011 onwards, it became increasingly difficult for gas-fired CHPP to achieve positive contribution margins. In 2013, basic conditions (falling electricity prices and rising gas prices) were such that only coal-fired CHPP were able to operate viably without any cogeneration subsidies. Gas-fired CHPP could only operate viably under these basic conditions with much higher revenue from sales of heat.

Figure 51: Contribution margin 2 of CHPP without cogeneration surcharge, specifically per installed capacity, in EUR2013/kW 2008-2013

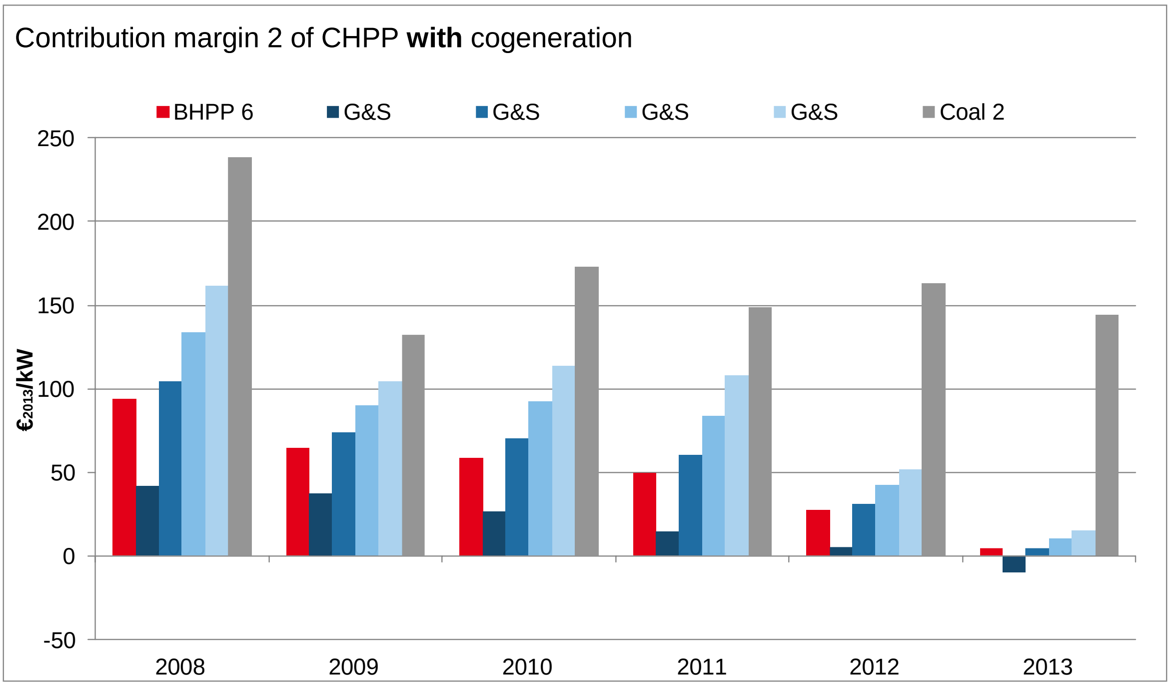


Source: Prognos 2014

The economic situation for **CHPP** which received **a subsidy under the Cogeneration Act** between 2008 and 2013 is illustrated in Figure 52. The ‘Coal 1’ plant is not included in that figure, as it corresponds to a type of plant built before 1990 which no longer receives any subsidy. From 2008 to 2012, all the types of plant with cogeneration subsidies investigated achieved positive contribution margins. However, contribution margin 2 of the gas-fired CHPP investigated fell continually after 2010. In 2013, the gas-fired CHPP ‘G&S 1’
was unable to operate viably even with subsidies. The other plants

achieved much lower contribution margins compared to previous years
(between 4 Euro2013 per kilowatt for BHPP 6 and 144 Euro2013 per kilowatt (Coal 2). Thus, in 2013, it was still possible for most fully depreciated plants to break even, but it was not possible to refinance investment costs.

Figure 52: Contribution margin 2 of CHPP with cogeneration surcharge, specifically per installed capacity, in EUR2013/kW 2008-2013

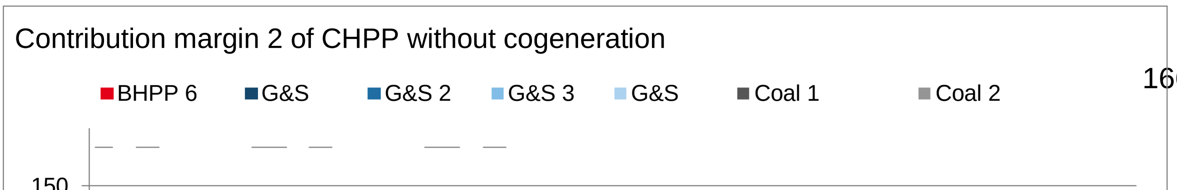


Source: Prognos 2014
'Coal 1' no longer receives any cogeneration subsidy and is therefore no longer included

2014 to 2020

The outlook for coming years is illustrated in Figure 53 and Figure 54 . Without subsidies, only the coal-fired public supply plants achieve a positive contribution margin 2 without any subsidy. From 2017, only Coal 2-type plants with a high electrical efficiency rating (45 %) can still do so. However, the contribution margins are so small even with these modern plants, that investments cannot be refinanced. Gas-fired CHPP cannot break even under these basic conditions in the next few years. They will continually report a loss.

*Figure 53: Contribution margin 2 of CHPP **without** cogeneration surcharge, specifically per installed capacity, in EUR2013/kW 2014-2020*

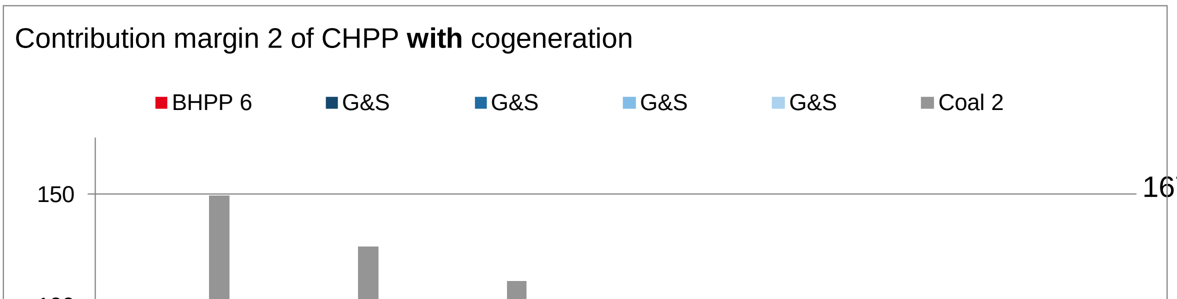


Source: Prognos 2014

If the current cogeneration subsidy is extrapolated, the situation for public supply CHPP is somewhat different. The contribution margins of plants with cogeneration subsidies are illustrated in Figure 54. Commissioning in 2014 is assumed for all plants. Thus subsidies also begin in that year for the first 30 000 hours' full load operation. Gas-fired CHPP with very a high efficiency rating of 50 or 55 % (G&S 3 and G&S 4) still achieve a positive contribution margin 2 up to 2016. Based on the basic economic conditions assumed, the DB 2 of these plants becomes negative from 2017 onwards. All smaller plants (BHPP 6, G&S 1 and G&S 2) have negative DB 2 over the entire period from 2014 to 2030. Even if current subsidies are maintained in the period up to 2020, it is still not possible for these plants to break even.

As with the figures for the period 2008 to 2013, the 'Coal 1' plant is not included in the figure below, as no new coal-fired public supply CHPP with such a low electrical efficiency rating are being built. Due to its relatively high number of hours' full load operation, the gas-fired plant 'Coal 2' only receives a subsidy in the first six years' operation and thus achieves contribution margins of between 150 $Euro_{2013}$ per kilowatt (2014) and 57 $Euro_{2013}$ per kilowatt (2019). Once subsidisation expires, the contribution margins fall to 15 $Euro_{2013}$ per kilowatt in 2020.

*Figure 54: Contribution margin 2 of CHPP **with** cogeneration surcharge, specifically per installed capacity, in EUR_{2013}/kW 2014-2020*



€2013/kW

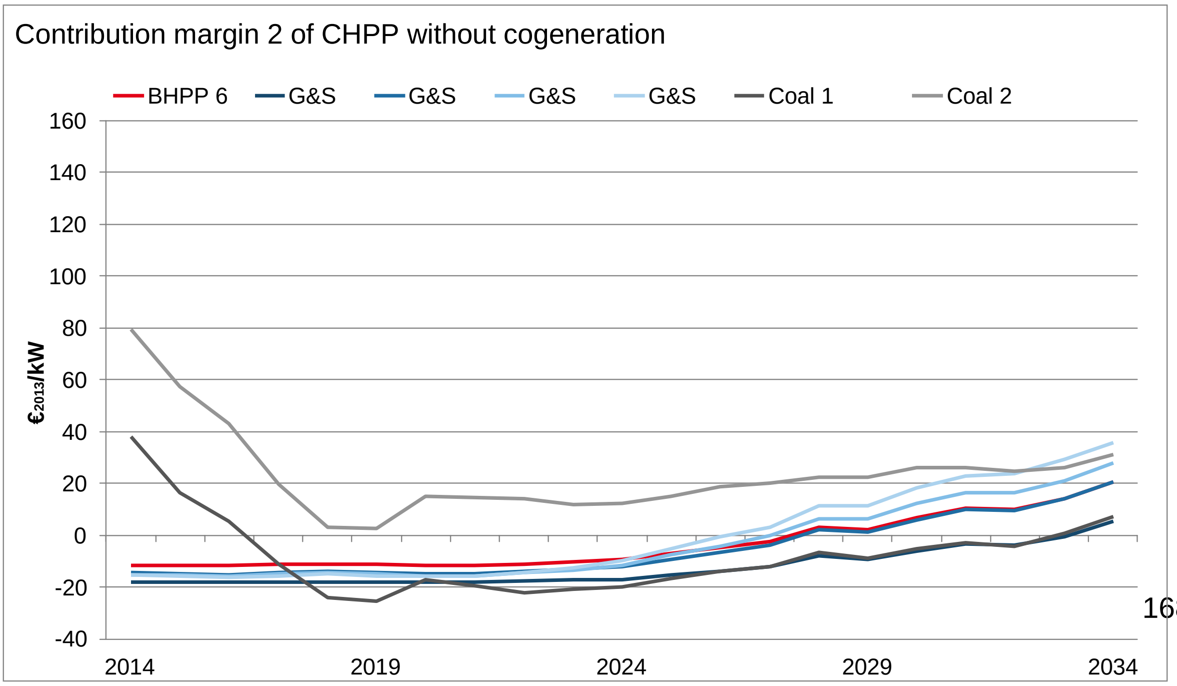
Source: Prognos 2014
'Coal 1' no longer receives any cogeneration subsidy and is therefore no longer included

Outlook to 2035

In the longer-term outlook from the mid-2020s, with rising CO_2 and electricity prices, the calculations for almost all types of public supply plants give a positive contribution margin 2, i.e. they can still break even without any cogeneration subsidy (Figure 55). Only 'G&S 2' and 'Coal 1' do not achieve a positive contribution margin 2 up to 2033. These plants have low electrical efficiency (35 % and 38 %), which reduces their chances on the electricity market. It is therefore debatable whether these types of plants will be operated up to the start of the 2030s. Only the 'Coal 2' type of plant can break even over the entire period; it is the only plant which has a positive contribution margin 2 throughout.

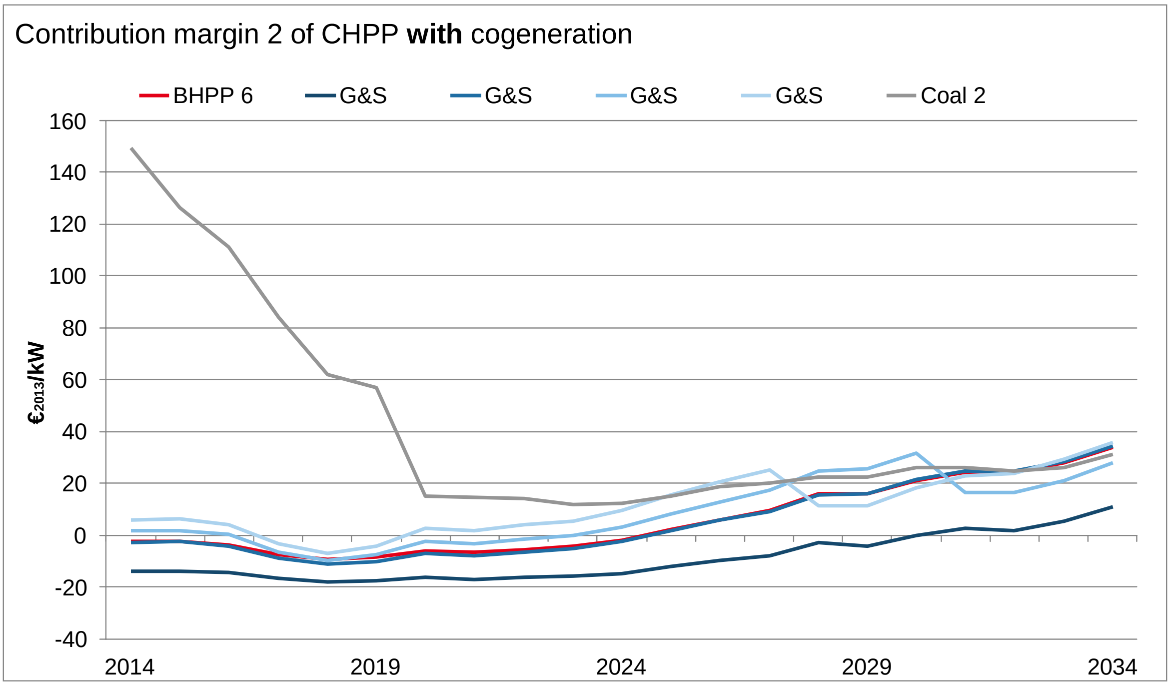
If current subsidies continue unchanged, most types of plant can achieve positive contribution margins somewhat earlier; nonetheless, they do not suffice by far in terms of encouraging investment (see Figure 56). Once 30 000 hours' full load operation (FLO) have been achieved and the subsidy ends, the contribution margins fall slightly in the short term. As less use is made over the year of
'BHPP 6', 'G&S 1' and 'G&S 2' type plants (see Table 93 in the annex) their subsidy limits of 30 000 FLO is not reached by 2035.

Figure 55: Contribution margin 2 of CHPP without cogeneration surcharge, specifically per installed capacity, in EUR2013/kW 2014-2034



Source: Prognos 2014

Figure 56: Contribution margin 2 of CHPP with cogeneration surcharge, specifically per installed capacity, in EUR2013/kW 2014-2034



Source: Prognos 2014
'Coal 1' no longer receives any cogeneration subsidy and is therefore no longer included

Rate of return on projects and amortisation period

In order to evaluate the potential of possible newbuild cogeneration projects, the overall yield on the project and the static amortisation period are calculated based on annual cash flows. The results can be found in Table 55.

Table 55: Rate of return and amortisation period for newbuild CHPP projects in the general supply network

		BHPP 6	G&S 1	G&S 2	G&S 3	G&S 4	Coal 1	Coal 2
Overall yield on project (1/a, real, before inflation)								
Without cogeneration subsidy	%	< -30 %	< -30 %	-19 %	-16 %	-13 %	-	-10 %
With cogeneration subsidy	%	-21 %	-29 %	-12 %	-11 %	-10 %	-	-7 %
Static amortisation period in years								
Without cogeneration subsidy	a	Investment is not self-amortising						
With cogeneration subsidy	a	Investment is not self-amortising						

Source: Prognos

As explained, existing plants which are already fully depreciated are barely economically viable. A newbuild plant which must cofinance both annual costs and its interest payments is unviable under these basic conditions, even with a subsidy. The yield on projects was negative in all cases considered. Investments in new CHPP in the public district heating supply system are self-amortising even if current subsidies are not maintained.

Conclusion

The only public district heating supply plants which can break even in the short term (up to 2020) under the basic conditions described are modern coal-fired CHPP. Without subsidies, gas-fired CHPP are not economically viable in any of the cases considered. Only plants with a high electrical efficiency rating in some years can achieve a positive contribution margin. As of 2017, as gas and electricity prices converge further, it will no longer be possible for any plants to achieve that. At present newbuild public CHPP for district heating with cogenerated electricity capacity of over 10 MW cannot be refinanced.

7.5.2 Property and industrial plants

In this chapter we describe the assumptions and results of the economic viability calculation for CHPP with electrical capacity of between 1 kW_{el} and 10 MW_{el} used in property supply and industrial plants. There is a very broad spectrum of **CHPP in the small capacity range** in practice which are used in various business models and supply situations in residential buildings and commercial and industrial undertakings. There is no point in mapping all conceivable cases; instead what are again typical, relevant supply models which are often realised are calculated here. The plants investigated are illustrated in Table 9 with all plant parameters and summarised in Table 56. Smaller plants that delivery to the public network are disregarded here. Their economic viability is comparable to the results calculated in Chapter 7.5.1 for BHPP 6.

The essential parameter for the economic viability of the plants investigated used here is the **overall rate of return on the project**. The rates of return calculated in this study are real rates of return obtained after deducting the inflation rate. With an inflation rate of 2 %, for example, real rate yield of 6 % corresponds to a nominal yield of 8 %.

The rate of return on the project is a criterion used by investors in order to decide whether or not to build a new plant. The minimum overall rate of return which triggers a decision to build differs between the various applications. One-off decisions can always be taken even if that minimum rate of return is not achieved, as different criteria may play an important part. For private users, for example, economic viability is not the only criterion; a preference for specific technologies may also tip them in favour of a particular type of plant. In the private sector, therefore, a lower yield of **2 to 3 %** suffices for many **home owners** who do not calculate in comparison with an alternative investment.

In the **residential economy**, in which investments can be refinanced over a longer period than in industry and in which a constant demand for power and heat prevails, a typical yield expectation is **6 %** real.

In the **CTS sector**, in which higher risk premia apply than in the residential economy, the threshold for an investment decision is a real yield on the project of **8 to 10 %**.

Industry has higher expectations of very short amortisation periods. Depending on the branch, a refinancing period of between two and eight years is required; that corresponds to a rate of return on the project of **between 12 %** (eight years) **and 50 %** (2 years).

The overall rate of return on projects is calculated in this study using the internal interest rate method. The annual cash flow (discounted based on real prices at 2013 prices) is obtained for each plant from its annual costs and revenue. The initial investment is input as a negative value in the first year. The costs include both the investment and fuel and variable and fixed operating costs, as well as the RES levy payable for privately used electricity. Revenue comprises procurement costs saved for privately used electricity, revenue for power delivered and heat produced, network user fees saved and the cogeneration surcharge. The calculation below only considers newbuild plants commissioned in 2014.

Table 56: Industrial and property CHPP

Plant:		**BHPP 1**	**BHPP 2**	**BHPP 3**	**BHPP 4**	**BHPP 5**	**ST 1**	**GT 1**	**BHPP 6**
Network level		LV	LV	LV	MV	MV	MV	MV	MV
Installed capacity	kW_{el}	1	5	50	500	1 999	5 000	10 000	10 000
Efficiency rating - electrical	%	26 %	27 %	34 %	39 %	42 %	25 %	30 %	46 %
Efficiency rating - thermal	%	66 %	66 %	57 %	51 %	48 %	60 %	55 %	42 %
Efficiency rating - overall	%	92 %	93 %	91 %	90 %	90 %	85 %	85 %	88 %

LV = Low voltage, MV = Medium voltage Source: IFAM, BHKW-Consult, IREES, Prognos

Plant-specific costs

All plants considered in this study are natural gas-fired. Natural gas-fired BHPP are the dominant technology within the group of motor-driven CHPP up to 10 MW electrical capacity. The fuel costs of natural gas-fired BHPP vary depending on the application, as different consumer groups pay different gas prices (see Table 63). The specific variable and fixed costs and the investment costs are listed in Table 9 by type of plant.

RES levy

The calculations take account of current rules on the RES levy payable on privately used electricity. Since the 2014 RES Act Amending Act, a pro rata RES levy must also be paid for privately used electricity from new CHPP. The levy is equal in this and coming years to:

- 30 % for power produced from 31 July 2014 to 1 January 2016
- 35 % for power produced from 31 December 2015 to 1 January 2017
- 40 % from 1 January 2017 onwards

That rules does not apply to small plants with less than 10 kW installed capacity and maximum private consumption of electricity of 10 MWh a year. In addition, plants in energy-intensive industries are excluded from the RES levy under special compensation rules.

Revenue

The power produced is used privately and delivered to the network in varying proportions in the applications considered. Revenue from sales of electricity therefore comprise two parts: First, the revenue from power delivered to the network, which is calculated from the base load price. Second, the electricity purchase costs saved through private use of the power produced, which is also classed as revenue. The reference revenue for these quantities of electricity corresponds to the retail price of electricity for the consumer group in question in which the CHPP is used (see Table 67).

The costs of alternative heat production in a gas-fired boiler are estimated as a heat credit. The heat costs are determined based on the gas retail price depending on type of consumption and the efficiency rating of the boiler. The costs of the boiler are disregarded as a peak load boiler is generally fitted as a backup for the CHPP.

The revenue from network user fees saved depend on the network level to which the plant is connected and are shown in Table 9 by type of plant. Aside from the parameters for each CHPP, the design on the property supplied and the individual tax and duty rules are important to consumers in terms of economic viability.

Cogeneration surcharge

The applications of the various CHPP are calculated with the current cogeneration surcharges applicable.
The surcharge, based on the size of the plant, is given in Table 8.

Mini-cogeneration incentive scheme

CHPP with electrical capacity of up to 20 kW are subsidised under the mini-cogeneration incentive scheme. The scheme is set out in the national section of the climate protection initiative.

One core objective of the scheme is to significantly increase the use of high-efficiency and flexible CHPP with capacity < 20 kW and to offer additional incentives for market development. The subsidised plants must meet high specifications in terms of primary energy savings and be prepared for the flexibility requirements of an electricity market with growing proportions of fluctuating renewable energies. That requires external control and regulation devices and an adequately sized storage facility. The terms of the scheme increase the investment costs slightly compared to ‘standard configurations’.

The first kW of electrical capacity is currently subsidised at EUR 1 425, the capacity between one and four kW is subsidised at EUR 285/kW, the capacity between four and ten kW is subsidised at EUR 95/kW and the capacity between 10 and 20 kW is subsidised at EUR 47.50/kW.

For a plant with five kW, that gives a subsidy of EUR 2 375. The subsidy guidelines are currently being revised based on experience since the introduction of the scheme in April 2012.

Cases considered

Table 57 lists the properties supplied which, in combination with the plants, represent typical applications for CHPP in the small capacity segment. The retail prices for electricity and gas in the consumer groups vary depending on the sector and the annual power and heat requirement. The retail price categories considered are also given in Table 57. Changes in natural gas and electricity retail prices are given in Table 63 and Table 67 subject to the general assumptions.

Table 57: Properties supplied

Sector	Property	Electricity	Heat	Electricity	Gas price
		MWh/a	MWh/a	Customer	Customer
Household	One-family house	4	20	Households	Households
Household	Two-family house	8	37	Households	Households
Apartment block	12-family house	42	120	Households	CTS1
Apartment block	60-family house	150	450	CTS1	CTS2
CTS	Services	50	125	CTS1	CTS1
CTS	School	80	700	CTS2a	CTS2
CTS	Retail trade	200	500	CTS2	CTS2
CTS	Hospital	1 000	3 500	CTS3	CTS2
CTS	Hotel	1 000	1 400	CTS3	CTS2
industry	e.g. machine engineering	5 000	12 500	Industry 3	Industry 3
industry	e.g. automotive supplier	10 000	25 000	Industry 4	Industry 4

industry	e.g. car factory	100 000	200 000	Industry 5	Industry 5
industry	e.g. paper	100 000	200 000	Industry 6	Industry 6
industry	e.g. chemicals	1 000 000	2 000 000	Industry 7	Industry 6

Source: IFAM, BHKW-Consult, IREES, Prognos

The CHPP have been sensibly combined with the properties supplied to give 23 cases investigated (Table 58).

Table 58: Cases considered

CHPP/Type of consumer	BHPP 1	BHPP 2	BHPP 3	BHPP 4	BHPP 5	ST 1	GT 1	BHPP 6	G&S 1
One-family house Full load hours: Private electricity	**Case 1** 5 000 50 %								
Two-family house Full load hours: Private electricity	**Case 2** 6 000 70 %	**Case 3** 3 000 40 %							
12-family house Full load hours: Private electricity use:		**Case 4** 6 000 10 %							
60-family house Full load hours: Private electricity use:		**Case 5** 7 500 40 %							
Services Full load hours: Private electricity use:		**Case 6** 6 000 80 %							
School Full load hours: Private electricity use:			**Case 7** 4 500 30 %						
Retail trade Full load hours: Private electricity use:			**Case 8** 4 500 50 %						
Hospital Full load hours: Private electricity use:			**Case 9** 7 500 90 %						
Hotel Full load hours Private electricity use:			**Case 10** 7 500 90 %						
Machine engineering Full load hours: Private				**Case 11** 6 000 80 %					
Automotive supplier Full load hours: Private				**Case 12** 6 500 90 %	**Case 13** 5 000 50 %				
Car factory Full load hours: Private electricity use:					**Case 14** 8 000 100 %	**Case 15** 5 000 100 %	**Case 16** 5 000 100 %	**Case 17** 5 000 100 %	**Case 18** 5 000 80 %

Paper Full load hours: Private electricity use:						**Case 19** 6 000	**Case 20** 6 000	**Case 21** 6 000	**Case 22** 5 000
Chemicals Full load hours: Private electricity use:									**Case 23** 6 000

Source: Prognos 2014

These details of these cases are as follows:

Case 1: One-family house:

We assumed a one-family house with three inhabitants. The electricity requirement is estimated to be approx. 4 000 kWh a year and the heat requirement is estimated to be approx. 20 000 kWh a year. In this property, a 1 kW micro-CHPP with combustion engine is used. That gives approx. 5 000 full load hours and a rate of private consumption of approx. 50 %. The CHPP covers 63 % of the heat requirement.

Case 2 and Case 3: Two-family house:

Two cases with different sized BHPP were generated for the two-family house property supplied. The two-family house is inhabited by 6-7 persons and has an annual electricity requirement of 8 000 kWh. The heat requirement is estimated to be approx. 37 000 kWh.

In Case 2, a combustion engine with 1 kW electrical capacity and 2.5 kW thermal capacity is installed in the two-family house. At around 6 000 full load hours a year, approx. 70 % of the cogenerated power supplied is used in the property supplied. The CHPP covers 41 % of the heat requirement.

In Case 3, a motor-driven mini-CHPP with 5 kW electrical capacity and 12.2 kW thermal capacity is used. At 3 000 operating hours, the CHPP covers nearly the entire heat requirement of the building. Due to the larger sizing, the rate of private electricity use is just 40 %. The CHPP covers 99 % of the heat requirement.

Case 4: Apartment block with 12 dwellings

The heat requirement of a 12-family house is approx. 120 000 kWh per annum. The entire electricity requirement (general electricity and electricity purchased by the 12 dwellings)
is estimated to be 42 000 kWh.

A motor-driven mini-CHPP with 5 kW electrical capacity and 12.2 kW thermal capacity is used. During 6 000 hours' full load operation, the CHPP covers 61 % of the heat requirement.

The cogenerated power is used solely to cover the general electricity requirement of the apartment block. The economic viability calculation does not assume any direct sales to tenants. The rate of private electricity use is 10 %.

Case 5: Apartment block with 60 dwellings

For the high-rise project, an annual heat requirement of 450 000 kWh and an overall electricity requirement of 150 000 kWh were assumed.

A motor-driven mini-CHPP with 5 kW electrical capacity and 12.2 kW thermal capacity is used and operated 7 500 hours a year.

The cogenerated power is used solely to cover the general electricity requirement of the apartment block. The economic viability calculation does not assume any direct sales to tenants. Due to the small sizing of the BHPP, the rate of private electricity use is approx. 40 %. The CHPP covers 20 % of the heat requirement.

Case 6: Small commercial/trade/services building

This is a CTS building with a higher specific electricity requirement than a residential building.

The building has an annual heat requirement of 125 000 kWh and consumes approx. 50 000 kWh of electricity a year.

A motor-driven mini-CHPP with 5 kW electrical capacity and 12.2 kW thermal capacity is used and operated 6.000 hours a year. Approx. 80 % of the electricity can be used in the property supplied. It is assumed that the BHPP operator and sole user of the building are one and the same. The CHPP covers 59 % of the heat requirement.

Case 7: School

The property supplies is a small grammar school or large secondary modern school measuring 7 000 square metres with gymnasium and around 600 pupils. The annual heat requirement is approx. 700 000 kWh a year and the electricity requirement is approx. 80 000 kWh a year.

The economic viability calculation assumes a motor-driven CHPP with 50 kW electrical capacity and 84 kW thermal capacity. It is operated for approx. 4 500 full load hours a year and has a rate of private electricity use of 30 %. The CHPP covers 54 % of the heat requirement.

Case 8: Medium-sized commercial/trade/services building

This property supplied (retail trade) is forecast to have an electricity requirement of 200 000 kWh and a heat requirement of 500 000 kWh.

Assuming a 50 kW plant with 84 kW thermal capacity and 4 500 full load hours a year, approx. 50 % of the cogenerated power would be used in the property supplied. The CHPP would also cover 76 % of the heat requirement.

Case 9: Hospital

The property supplied is a primary care hospital with around 180-200 beds. An annual heat requirement of 3 500 000 kWh is forecast. The annual electricity requirement is approx. 1 000 000 kWh.

The economic viability calculation assumes a motor-driven CHPP with 50 kW electrical capacity and 84 kW thermal capacity. It is operated for approx. 7 500 full load hours a year and has a rate of private electricity use of 90 %. The CHPP covers 18 % of the heat requirement.

Case 10: Hotel

A spa/conference hotel with around 200 to 240 rooms has an annual heat requirement of 1 400 000 kWh and an annual electricity requirement of approx. 1 000 000 kWh.

Assuming a 50 kW plant with 84 kW thermal capacity and 7 500 full load hours a year, approx. 90 % of the cogenerated power would be used in the property supplied. The CHPP would also cover 45 % of the heat requirement.

Case 11: Industry – Machine engineering

A motor-driven mini-CHPP with 500 kW electrical capacity and 654 kW thermal capacity is used which supplies heat and power for 6 000 hours' full load operation a year. The property supplied uses 80 % of the power supplied. The CHPP covers 31 % of the heat requirement.

Case 12: Industry – Automotive supplier

In this case, a property with 25 000 000 kWh annual heat requirement and 10 000 000 kWh annual electricity requirement is considered.

The CHPP installed in this property supplied, with 500 kW electrical capacity and 654 kW thermal capacity, has a rate of private electricity use of 90 % at 6 500 hours' full load operation a year. The ratio of cogenerated heat to heat requirement is 17 %.

Case 13: Industry – Automotive supplier

Case 13 differs from Case 12 solely in terms of the size of the CHPP used. The automotive supplier with a heat requirement of 25 million kWh a year and an annual electricity requirement of 10 million kWh is supplied by a CHPP with electrical capacity of 1 999 kW and thermal capacity of 2 285 kW. Assuming 5 000 hours' full load operation a year, the rate of private electricity use is 50 %. The heat requirement is covered to 46 %.

Cases 14 to 18: Industry – Car factory

For an industrial undertaking (e.g. car factory) with an annual heat requirement of
200 GWh and an annual electricity requirement of 100 GWh, we considered CHPP with just under 2 MW_{el} to 20 MW_{el}.

The BHPP with around 1 MW would only be able to cover a small part of the electricity and heat requirement of the undertaking and would be operated as a continuous run plant at around 8 000 full load hours to cover the base load. All the electricity produced could be used in the undertaking itself. As a rule,
CHPP for this type of consumption are bigger sized, so that the plant can cover a larger proportion of electricity and heat consumption.

The CHPP of 5 MW to 20 MW investigated would reach around 5 000 full load hours in this case. Up to the 20 MW case, all the electricity produced could be used by these plants themselves.

Cases 19 to 22: Industry – Paper factory

A more energy-intensive industrial undertaking was considered here (e.g. a paper factory). The annual electricity and heat requirement assumed (100 GWh and 200 GWh) are as large as in the previous case considered (car factory). Unlike the non-energy-intensive car factory, the electricity purchase costs in this case are much lower due to the reduced RES levy.

We considered a CHPP with capacity of 5 MW to 20 MW for this type of consumption. For the smaller sized plants (5 MW to 10 MW), we assumed 6 000 hours' operation and private use of all the electricity. If a larger sized plant (20 MW) is operated, potential use falls to 5 000 hours and the rate of private use of electricity also falls to 80 %.

The full load hours assumed are somewhat higher in this case than the mean full load hours of approx.
4 400 h/a of the power production plants in the paper industry [Destatis 2013]. The statistics map all existing power plants (incl. old plants and backup power plants) in this branch. For new power plants considered in the economic viability analysis, the higher operating hours assumed are realistic.

Case 23: Industry – Chemical plant

This type of consumption describes a very large energy-intensive undertaking with annual electricity consumption of one TWh and heat consumption of 2 TWh. Undertakings in the chemical industry or mineral oil processing industry are typical examples. Power production plants in both those branches report approx. 5 000 full load hours a year [Destatis 2013]. For the newbuild 20 MW plant investigated here, run-time of 6 000 hours a year is forecast. With an even bigger plant, a somewhat smaller number of full load hours would be expected.

In order to calculate the **rate of return on projects**, we used the typical full load hours and individual rates of private use of electricity given in Table 58. The calculation period encompasses each plant's service life.

Results

The rates of return on projects for the 23 cases considered are given **with the cogeneration surcharge** in Table 59. The non-economically viable cases with a negative rate of return on the project are shown in red. The cases which give the necessary minimum rate of return on the project in each application are shown in light blue.

Table 59: Rate of return on newbuild property and industry CHPP projects, with cogeneration surcharge

With cogeneration surcharge	**BHPP 1**	**BHPP 2**	**BHPP 3**	**BHPP 4**	**BHPP 5**	**ST 1**	**GT 1**	**BHPP 6**	**G&S 1**
One-family house	-27 %								
Two-family house	-15 %	-17 %							
12-family house		-36 %							
60-family house		-4 %							
Services		4 %							
School			-4 %						
Retail trade			5 %						
Hospital			30 %						
Hotel			30 %						
Machine engineering				41 %					
Automotive supplier				47 %	34 %				
Car factory					79 %	25 %	50 %	50 %	26 %
Paper						0 %	15 %	14 %	6 %
Chemicals									6 %

Red: Negative rate of return on project
With blue background: Economically viable, as minimum rate of return on type of consumption project is achieved Source: Prognos 2014

All **residential property** supply cases (Cases 1 to 5) give a **negative rate of return on the project** based on the assumptions made. The reasons for this are, first, the higher fuel prices and, second, the low rate of private use of the electricity in these supply cases. Moreover, the very small plants with capacity of 1 kW_{el} and 5 kW_{el} which are suitable for these properties have the highest specific investment costs. For **BHPP 1** there is no economical viable application. For **BHPP 2** the only positive rate of return on the project is in Case 6 (commercial undertaking). However, the overall rate of return determined for that supply case (4 %) is well below the necessary rate of return on the project (10 %).

If the **mini-cogeneration incentive scheme** is taken into account, BHPP 1 and BHPP 2 are slightly more economically viable. For BHPP 1, the rate of return on the project improves in the cases considered by just one percentage point. The results for BHPP 2 improve by approx. two percentage points. For BHPP 2 in the services sector, the **minimum rate of return** of 8 % **is still not achieved**.

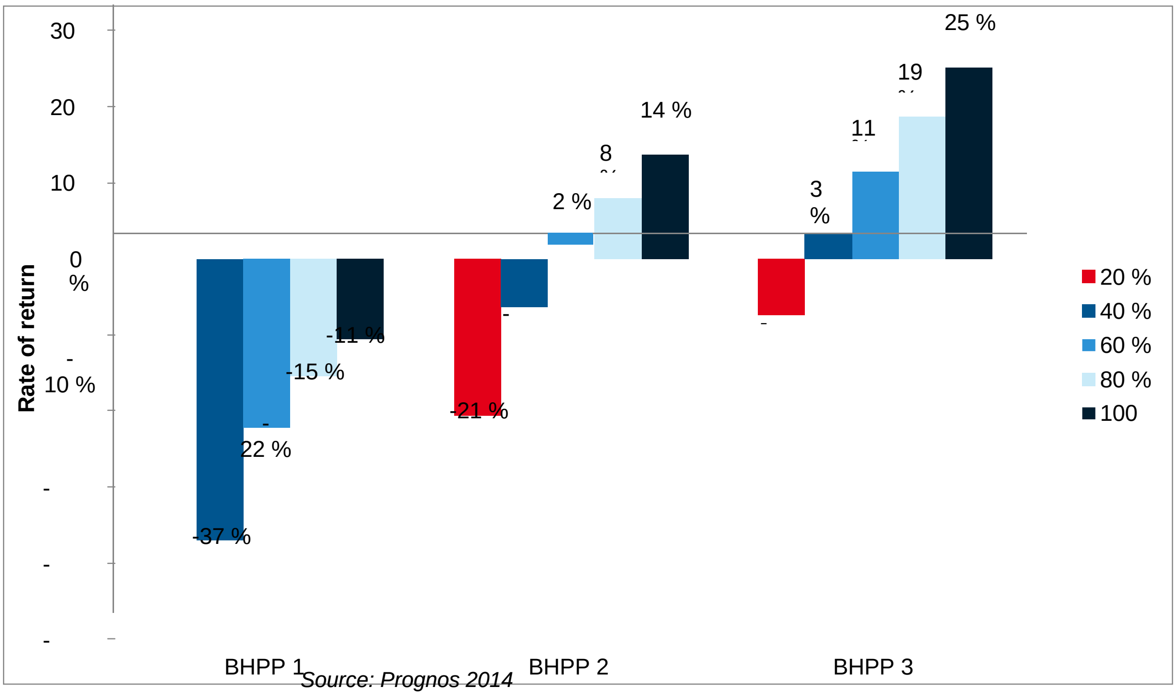
For **BHPP 3**, economic viability depends enormously on where it is used. If it is installed in a school, it has a negative rate of return on the project (-4 %). The main reason for that is the very low rate of private use of electricity in this application (30 %). If it is installed in a retain undertaking, the result becomes positive due to the 50 % rate of private use of electricity. However, the 5 % rate of return on the project is below the level needed to implement the project. The situation changes if the plant is used in the cases considered of a hotel or hospital. With a 90 % rate of private use of electricity at 7 500 full load hours, the plant is economically viable and, with a rate of return on the project of 30 %, is well above the minimum rate of return required for such properties.

Aside from the selected cases described, numerous other **cases were optimised for their application** in the **< 50 kW capacity segment** and appeared to be much more economically viable. In particular, the rate of private use of electricity achievable had a huge impact on the economic viability of the plant. If, for example, the tenants of an apartment block set up a non-trading partnership, higher rates of private use of electricity can be achieved. The figure below gives an overview of the rate of return on projects for BHPP 1 to 3 as a function of rate of private use of electricity. All the calculations are based on an assumed
5 000 full load hours. The price of electricity to households and to commerce (CTS1) have been used the reference electricity prices for BHPP 1 and BHPP 2 respectively. The results of the calculation are given in Figure 57.

BHPP 1 (1 kW) is **not economically viable** over the 10-year period considered, even with **private use of all electricity generated** and taking account of subsidisation under the mini-cogeneration incentive scheme.

A 5 kW plant (BHPP 2) and a 50 kW plant (BHPP 3) achieve **positive rates of return on the project with 60 % and 40 % private use**, based on 5 000 hours' operation. The higher the rate of private use, the higher the rates of return on these plants in numerous sectors which are attractive to investors.

Figure 57: Rate of return on projects for BHPP 1 to 3 as a function of rate of private use (assumption: 5 000 hours' full load operation)



Source: Prognos 2014

The larger types of plant (**BHPP 4** and **BHPP 5**) are used solely in industry in the sample cases generated for the study. BHPP 4 achieves a rate of return on the project of over 40 % in the applications investigated (Cases 11 and 12). This type of plant is economically viable in the cases described.

Even **BHPP 5** is economically viable in the applications investigated (Cases 13 and 14). However, the rates of return on the project differ markedly when the plant is used in industrial undertakings with average electricity consumption of 10 000 MWh (Case 13) and 100 000 MWh (Case 14). The main reason for the different rates of return on the projects (34 % in Case 13 and 80 % in Case 14) is the different rate of private use of electricity in the applications considered. In Case 13 it is just 50 %, whereas in Case 14 all the electricity is used (100 %). This is also a sign of the planning maxims often encountered in the industrial sector, whereby CHPP are not designed based on the heat requirement and are sized primarily such that no cogenerated electricity is delivered to the public network.

The steam turbine **(DT 1)** clearly illustrates that economic viability depends on the application. The steam turbine used in a car factory (Case 15) has an economically viable rate of return on the project of 25 %, provided that the undertaking accepts a refinancing period of 4 years. However, in an energy-intensive industry, such as the paper industry (Case 19), the same plant has a zero rate of return on the project even if all the electricity is used privately. The reason for this is that, in Case 19, the undertaking pays much lower electricity prices as it is exempt from the levies.

For the gas turbine **(GT1)**, the result tends to be similar. However, as it is more efficient that a steam turbine and has lower specific investment costs, the rates of return on the project are higher. Used in industrial undertakings such as a car factory (Case 16) or the paper industry (Case 20), rates of return on the project of 50 % (Case 16) or
15 % (Case 20) are possible. In Case 20 (use of a gas turbine in an energy-intensive industry), the project will only be successful if the undertaking accepts an investment refinancing period of just under seven years.

Plants BHPP 6 and G&S1 are used both in the public district heating supply (see that section for conclusions on their economic viability) and in industry. When used in a large industrial undertaking, such as a car factory (Case 17), **BHPP 6** gives a rate of return of 50 % on the project, which is thus viable. In energy-intensive industries, such as the paper industry (Case 21), on the other hand, the rate of return on the project falls to 14 %, as they enjoy cheaper electricity prices and are exempt from levies. With that rate of return, the project can only be implemented in undertakings that accept a refinancing period of over seven years.

The lower electricity prices for energy-intensive industries in Cases 22 and 23 prevent the use of a large G&S plant **(G&S1)**. In the 'paper' and
'chemicals' applications it only achieves a rate of return on the project of 6 %. Thus these applications fall well below the minimum rate of return for industry of 12 %. In the 'car factory' application (Case 18), on the other hand, a rate of return on the project of 25 % can be achieved, allowing the plant to be amortised within four years. That is still acceptable to many undertakings.

Results without cogeneration subsidy

Naturally the rate of return on projects is worse in all cases without cogeneration subsidies. In energy-intensive industry, the gas turbine plant (GT1) and BHPP 6 now fail to achieve the minimum rate of return on the project.

Table 60: Rate of return on newbuild property and industry CHPP projects, without cogeneration surcharge

With cogeneration surcharge	**BHPP 1**	**BHPP 2**	**BHPP 3**	**BHPP 4**	**BHPP 5**	**ST 1**	**GT 1**	**BHPP 6**	**G&S 1**
One-family house	<-40 %								
Two-family house	-23 %	-35 %							
12-family house		<-							

60-family house		-30 %							
Services		-7 %							
School			-52 %						
Retail trade			-12 %						
Hospital			13 %						
Hotel			13 %						
Machine engineering				29 %					
Automotive supplier				33 %	21 %				
Car factory					58 %	19 %	39 %	39 %	19 %
Paper						-6 %	4 %	3 %	1 %
Chemicals									2 %

Red: Negative rate of return on project
With blue background: Economically viable, as minimum rate of return on type of consumption project is achieved Source: Prognos 2014

Conclusion

Smaller plants, especially in residential properties do not achieve a positive rate of return under current conditions. With a negative rate of return on projects, plants are only built here and there based on non-monetary criteria.
Although small to medium-sized plants for supplying properties may achieve a positive rate of return, it is often below the minimum rate of return and, as a rule, these projects are not implemented. Overall, plants in CTS and residential buildings are only economically viable in one-off cases.

For plants supplying properties, economic viability depends enormously on the rate of private use of electricity. Very good rates of return on projects can be achieved in certain applications, such as hotels or hospitals. In sectors such as the residential sector, however, projects are very hard to implement.

The reasons for this are, first, the higher specific costs of the smaller plants and, second, the low rate of private use of the electricity generated. Cogeneration subsidies cannot change these basic restrictions.

Larger property and industrial CHPP, on the other hand, can be erected and operated in suitable applications under present subsidy law. Numerous applications achieve a sufficiently high rate of return on the project without any cogeneration subsidy. The highest rates of return on projects are achieved where plants attain high capacity utilisation and where a large proportion of the electricity can be used by the operator itself. This is usually the case in industrial sectors with a high and generally constant demand for power and heat.

Consumers in energy-intensive industries enjoy relief on levies and electricity is therefore cheap to buy; therefore, although a new

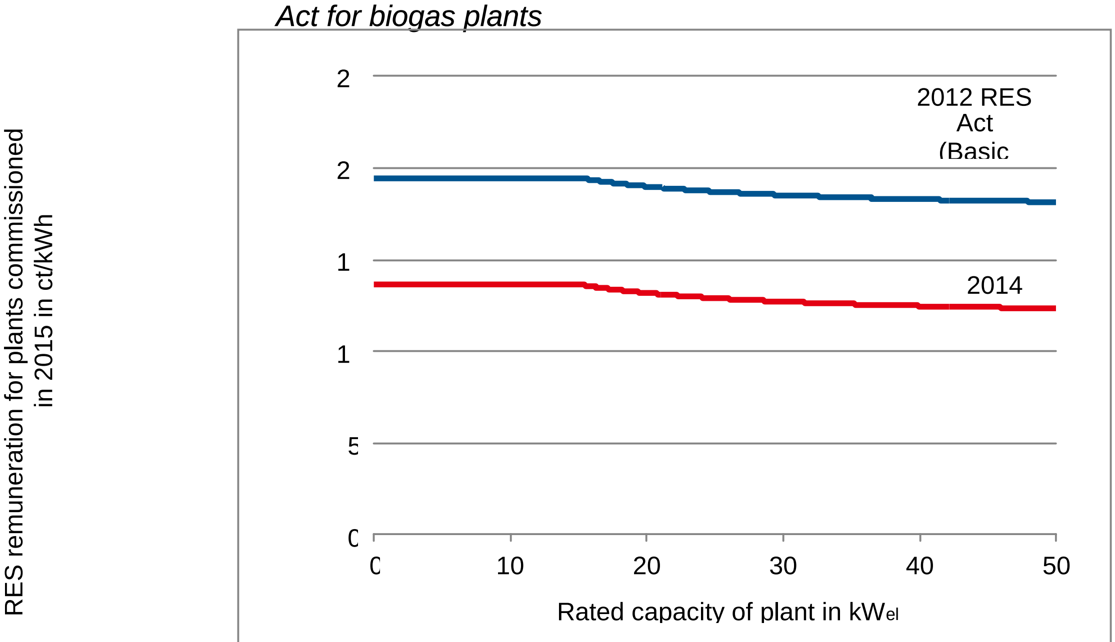
CHPP would be expected to generate a positive rate of return on the project, it would tend to be below the minimum rate of return for implementing the project. Adjusting subsidies could generate new momentum in this segment.

7.5.3 Role of biomass cogeneration

The RES subsidy has triggered a marked increase in biomass CHPP over recent years. The installed electrical capacity of biogas and biomethane plants rose between 2000 and 2013 from approx. 500 MW_{el} to approx. 3 750 MW_{el}. The installed capacity of biomass CHPP rose over the same period from approx. 250 MW_{el} to more than 1 500 MW_{el}. In particular, the 2004 and 2009 RES Act Amending Act triggered very dynamic expansion of the biomass sector. Between 2009 and 2011, the additional biogas plants built averaged 500 MW_{el}. The 2012 RES Act Amending Act has already markedly reduced newbuilds, especially in the case of biogas plants. In 2013, newbuilds still accounted for 200 MW_{el}.

We assume, in light of the 2014 RES Act Amending Act, that the number of newbuild biomass plants will continue to fall in coming years. First, the RES subsidy for newbuilds is capped at 100 MW_{el} a year. Second, the remuneration rates have been adjusted. This has seriously impaired the economic standing of biomass plants. In previous versions of the RES Act, the remuneration for electricity from biomass comprised basic remuneration and an additional, optional, component specific to the undertaking. In the 2012 RES Act, for example, it was possible to increase the basic remuneration by up to 8 cent/kWh by using certain types of biomass. These additional components have been abolished in the current version of the RES Act; now only the basic remuneration is paid. Figure 58 illustrates how this impacts on biogas plants up to 500 kW_{el} . Aside from small plants < 75 kW_{el}, which mainly use slurry, the remuneration in the examples is approx. four to five cent/kWh lower than under the 2012 RES Act. Moreover, this high subsidy is only payable up to a rated capacity of 50 % of the installed capacity.

Figure 58: Examples of payments under the Renewable Energies Act for biogas plants



Source: Prognos 2014 based on RES Act

The adjustments for biomethane-fired plants, i.e. biogas processed to the natural gas quality, are even more marked. Aside from the bonus for the fuel class, the gas processing bonus for newbuild biomethane BHPP has also been abolished. This reduces the remuneration in the examples by approx. five to eight cent/kWh compared to under the 2012 RES Act.

7.6 Cogeneration and Cogeneration Act levy costs – Prognosis

Estimating the long-term development of cogeneration is a very uncertain exercise, due to the numerous relevant parameters and potential impact of political decisions. For the relatively short period up to 2020, it is possible to make a prognosis based on the current foreseeable development.

The prognosis is based on current cogenerated power production. It takes account of the main developments in cogeneration for general supply, industrial cogeneration and biogenic and small-scale cogeneration. These are presented below together with their estimated impact.

The prognosis takes account of newbuild projects already announced and the results of the economic viability analysis in Chapter 7.5. It also takes account of the changes to private consumption made in the 2014 RES Act. The Cogeneration Act is extrapolated in its present form. It disregards potential effects of the introduction of a capacity market in the future.

The prognosis for cogenerated power production takes account of the larger newbuild CHPP with net capacity of approx. 3.4 GW listed in Table 61. We assume, given current market conditions, that coal-fired power plants can be operated on average for approx. 6 000 hours a year and that natural gas-fired power stations can be operated on average for approx. 3 000 hours a year. Some new CHPP deliver to existing district heating networks or replace existing plants. The small run-time of these power stations is taken into account in the cogeneration prognosis.

Table 61: Large CHPP projects in progress and subsequently approved by undertakings

Undertaking	**Name of plant**	**Year commissioned**	**Electrical capacity in MW**
UPM GmbH Werk Schongau	HKW3 UPM Schongau	2014	70
Müller Sachsen GmbH	G&S CHPP	2014	35
Volkswagen AG	BHKW Braunschweig	2014	10
EnBW Erneuerbare und Konventionelle Erzeugung AG	Rheinhafendampfkraftwerk Bl. 8	2014	842
Stadtwerke Düsseldorf AG	Kraftwerk Lausward	2016	595
Stadtwerke Flensburg GmbH	Heizkraftwerk Flensburg	2015	73
Grosskraftwerk Mannheim AG	GKM	2015	843
RheinEnergie AG	Niehl 3	2016	446
E.ON Kraftwerke GmbH	Datteln	2018 (assumed)	1 055
Vattenfall Europe Wärme AG	Lichterfelde	2016	300
Flughafen München GmbH	Energiezentrale 2016	2016	17
GuD Zeitz GmbH	GuD Zeitz	2017	130

Source: Network Development Plan [Netzentwicklungsplan], Prognos AG

According to the list of power plants issued by the Federal Network Agency, additional CHPP with net electrical capacity totalling around 4.5 GW are planned. However, these power plants are not yet under construction. We consider, given the current difficult economic situation for newbuild projects, that these projects are unlikely to be implemented under current market conditions. Therefore they have been disregarded in the prognosis of the development of cogeneration up to 2020.

Existing CHPP will be decommissioned between now and 2020. This will affect old coal- and gas-fired power plants in particular. For example, the last three blocks of the Scholven CHPP will be decommissioned in 2015. The Federal Network Agency keeps an official list of power plants notified for decommissioning which, like the list of newbuilds, is updated on a regular basis. However, as with the newbuilds notified, we do not expect all decommissioning projects to be implemented. We have assumed for the prognosis that CHPP in an order of magnitude of 2 to 3 GW will be decommissioned between now and 2020.

In the 1 kW to 10 MW capacity segment, an average of just under 300 MW a year was erected between 2010 and 2013 (see Chapter 7.2). This expansion has been relatively stable over recent years. In light of the economic viability calculation carried out in this study, we assume that this expansion will remain constant at that level up to 2020. The negative impact of the RES levy on electricity for private use and depressed revenue for network deliveries, on the one hand, and the higher levies on electricity purchases has been felt across the entire capacity segment in recent years.

Due to the reduction in remuneration rates for biomass plants in the

20114 RES Act, and the development policy objective of 100 MW a year, slow growth in biomass-fired cogeneration is expected up to 2020. Expansion of 50 MW a year would appear to be a realistic forecast. It should be noted here that new biogas-fired power plants subsidised under the RES Act are no longer required to connect to a heating network. This may impact on the proportion of cogeneration in the case of biomass- and biogas-fired plants.

Given the current market situation, with relatively high fuel prices and low wholesale electricity prices, we do not expect any additional biomass CHPP to be built without subsidisation under the RES Act.

Based on these developments, the prognosis is as follows: Net cogenerated power production will remain more or less at the same levels as in 2011-2013 up to 2020. Due the very mild weather in the first four months of 2014, net cogenerated power production this year is expected to be approx. 91 TWh. According to the monthly electricity supply reports, net cogenerated power production in the general supply system from January to May 2014
was around 4 TWh less than in the same period in 2013. Gas-fired plants accounted for 2.7 TWh of that reduction.

Table 62: Cogenerated net power production up to 2020

Figures in TWh	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Net electricity production	595	580	593	592	591	590	589	587
Export balance	34	35	36	37	38	39	40	41
Net cogenerated power production	**96**	**91**	**94**	**97**	**96**	**95**	**95**	**98**
General supply	50	44	48	49	46	44	42	44
Coal	14	13	14	14	14	14	13	13
Lignite	5	4	5	5	5	5	5	5
Mineral oil	0	0	0	0	0	0	0	0
Gas	26	22	23	25	21	19	18	20
Renewables	2	2	2	2	2	2	2	2
Rest	3	4	4	4	4	4	4	4
Industrial cogeneration	30	30	30	30	31	31	32	33
Cogeneration under 1 MW_{el} not	5	6	6	6	7	7	8	8
Biogenic cogeneration not reported	12	12	12	13	13	13	14	14
Cogeneration (%) (in relation to net production)	**16.2 %**	**15.9 %**	**16.1 %**	**16.7 %**	**16.4 %**	**16.4 %**	**16.2 %**	**16.8 %**

Source: Prognos

The development of cogeneration will differ from application to application. For CHPP for general supply, the economic situation will probably cause a decline in cogenerated power production. As explained in Chapter 7.5, the economically viable operating times of natural gas-fired CHPP will decline still further in the next few years.

The economic situation of lignite- and coal-fired power stations has also deteriorated over recent years due to the very low wholesale electricity prices. Nonetheless, we expect stable production from these plants up to 2020, due to their lower marginal power production costs compared to natural gas-fired plants. In district heating networks supplied by both natural gas-fired and coal-fired plants, coal-fired cogeneration may compensate in part for the smaller-scale operation of natural gas-fired plants.

The economic viability calculation illustrated that it is currently not possible for many CHPP to break even based on the assumptions made. Nonetheless, the prognosis does not include any premature decommissioning of CHPP, as a serious estimate of the scope of temporary or definitive closures is not possible from today's point of view. If far more cogeneration capacity is decommissioned due to economic reasons and heat production is then replaced by boilers, cogenerated power production in coming years
will be even lower in the district heating sector.

A slight increase compared to current levels is anticipated for industrial cogenerated power production up to 2020. There is attractive potential in particular for undertakings and branches with high electricity purchase costs and high heat and power consumption. The very low prices on the wholesale electricity market only have a relatively minor impact on industrial cogeneration compared to general supply plants. The exception here is energy-intensive undertakings which enjoy low electricity prices.

The biggest impact applies in the relatively short term to undertakings which have designed their CHPP on the heat side and delivered a large part of the electricity produced (from natural gas) to the public network. As the network delivery price is currently no longer economically viable in many cases, some undertakings are trying to reduce their network deliveries.

In order to achieve the 25 % cogeneration target by 2020, cogenerated power production would have to be increased in 2020 compared to the current prognosis from 98 to 147 TWh. This study does not investigate in detail the basic conditions under which and the measures by which the cogeneration development target can be reached.

Differentiated investigations would be needed in order to reliably estimate the measures needed (e.g. increase in cogeneration subsidies). Cogenerated power production compared to the prognosis prepared could be achieved by building new plants, modernising plants (increasing plant capacity or cogeneration index) and by increasing the run-time of or maintaining existing CHPP. It would also be necessary to realistically allocate additional quantities of electricity to individual cogeneration sectors (size of plant, type of fuel and application) based on existing potential.

Given the lead time needed for large new power plant projects and the capacity expansion needed, it does not at present appear that the target will be achieved by 2020, even with much higher subsidies.

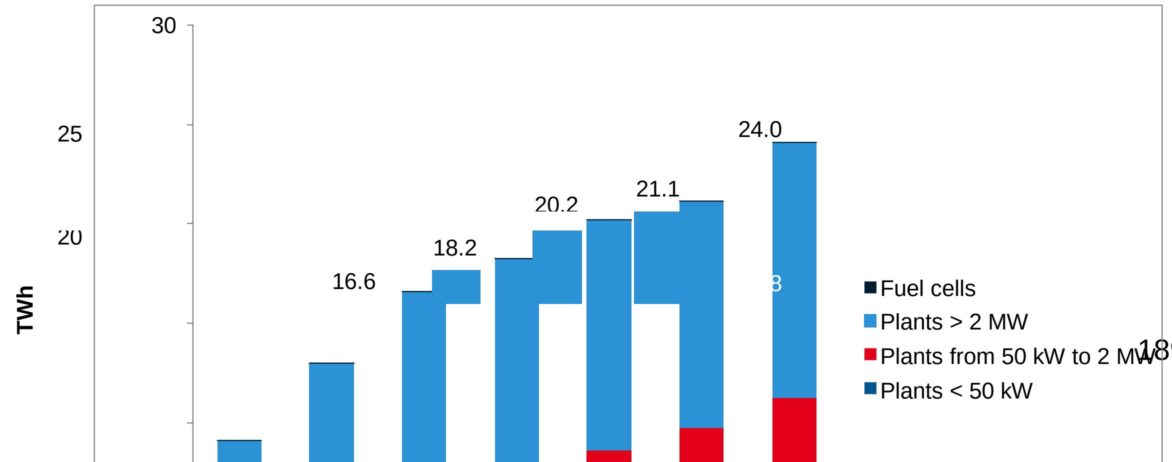
Roughly speaking, additional new plants with approx. 10 GW capacity or additional cogenerated power production of approx. 50 TWh and corresponding development of heat sinks would be needed in order to attain the target. The existing cap in the Cogeneration Act would need to be raised considerably in order to implement the newbuilds needed. A reliable estimate of the volume of subsidies needed cannot be made here. Based on the simplified assumption that a mane cogeneration surcharge of 4-6 cents/kWh is needed, as a rough guide an additional EUR 2 to 3 billion would be needed in subsidies in 2020. Other political action (such as capacity elements) or changes in the market situation in the next few years might improve the economic situation of cogeneration projects and thus reduce the subsidy requirement.

The four transmission system operators in Germany prepare an annual medium-term prognosis of the future development of subsidised cogenerated power production and remuneration payments.

The current medium-term prognosis (December 2013) anticipates an increase in eligible power production in the next few years. According to the medium-term prognosis, 24 TWh of cogenerated power will be subsidised in 2018. Together with the subsidisation of heating networks and storage facilities, this will increase the subsidies to just over EUR 700 million by 2018.

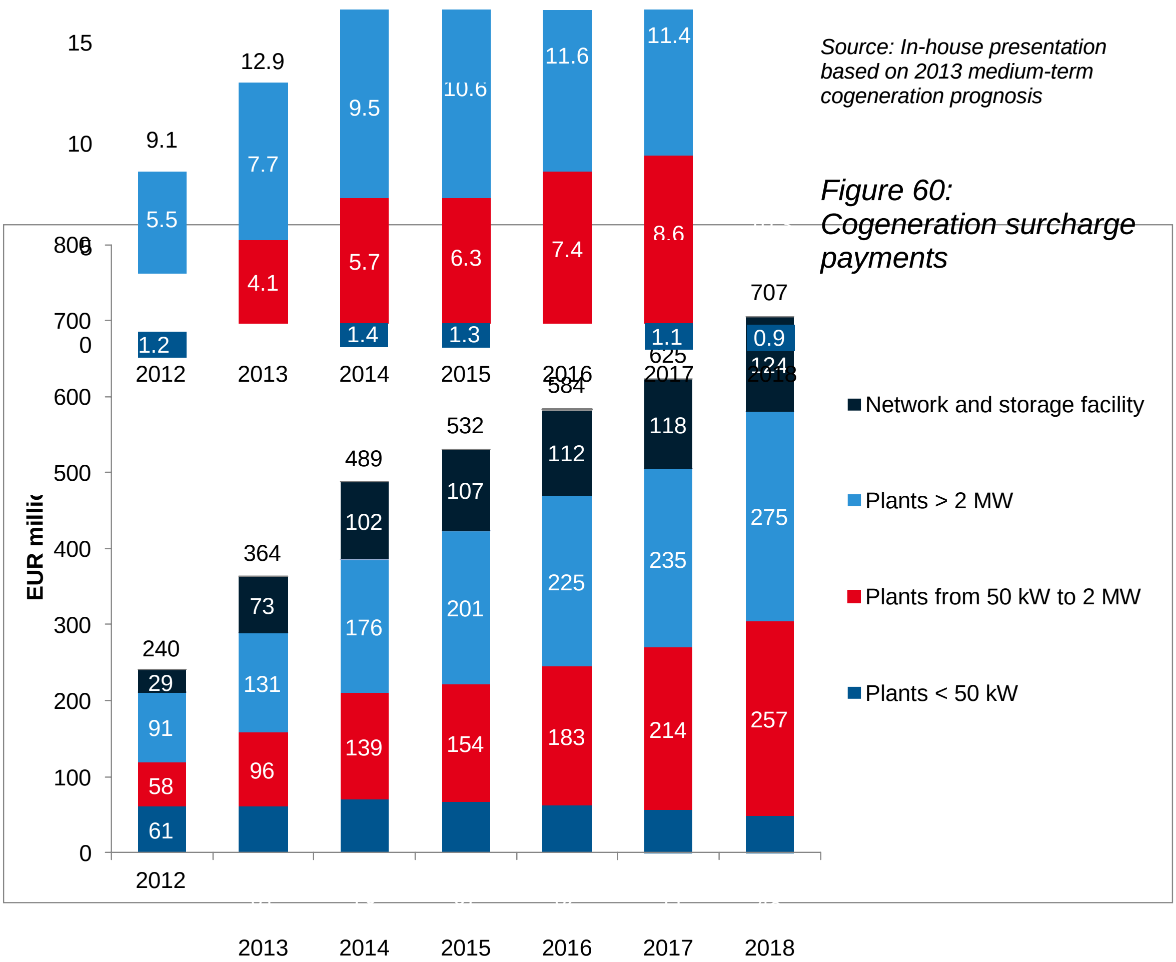
Based on the assumptions made in this study on further expansion of cogenerated power production, the results of the medium-term cogeneration prognosis appear to be realistic. Unless the Cogeneration Act is adjusted, the volume of subsidies, in conjunction with less cogeneration development, might be somewhat smaller.

Figure 59: Eligible quantities of cogenerated electricity



Source: In-house presentation based on 2013 medium-term cogeneration prognosis

Figure 60: Cogeneration surcharge payments



Source: In-house presentation based on 2013 medium-term cogeneration prognosis

7.7 Recommendations for further changes to the Cogeneration Act

7.7.1 General recommendations

The current configuration of subsidies under the Cogeneration Act is to be maintained in its basic form. Subsidisation of cogenerated power production on the operating side does not only improve the general economic viability of the subsidised plants; it also stimulates operation and thus results in primary energy and CO_2 savings compared to uncoupled generation. Conversion of subsidies to capacity subsidies, which is conceivable in theory, would mean that CHPP run less often, as the subsidy would no longer affect the plant's marginal costs.

The subsidies for expansion of heating and cooling networks and heat and cooling storage facilities in the last two Cogeneration Act Amending Acts has resulted in greater expansion activity. Subsidisation in the form of investment cost subsidies has proven its worth and should be continued.

If appropriate surcharge rates are defined for CHPP, the highly volatile market environment of recent years and probably of coming years must be taken into account. Due to the strong and sometimes unforeseeable fluctuations in electricity and fuel prices, as well as in CO_2 certificate prices, it makes sense to review cogeneration surcharge rates at regular, possibly, short intervals.

The relevant basic and market conditions have deteriorated considerably over recent years for CHPP which deliver most of their electricity to the public network. The fixed subsidy rates under the Cogeneration Act did not suffice in this phase to offset the impact of the low base load prices on the electricity exchange. The volatile or declining revenue from sale of electricity cause uncertainty among investors and operators. However, expansion at minimum cost depends on continual expansion, especially in connection with heating networks.

By way of approximation, an additional 50 TWh of cogenerated electricity production would be needed in order to attain the cogeneration target. The existing cap in the Cogeneration Act needs to be raised considerably. Based on the simplified assumption that a cogeneration surcharge of 4-6 cents/kWh is needed, as a rough guide an additional EUR 2 to 3 billion would be needed in subsidies in 2020. Other political action (capacity elements) or changes in the market situation might improve the economics of cogeneration projects and thus reduce the subsidy requirement.

7.7.2 CHPP for general supply

It is not economically viable under current market conditions to build new natural gas- and coal-fired CHPP operated in the general supply sector. In order to generate expansion in this segment, subsidy surcharges would need to be increased considerably. Resolving the very poor economic situation of new CHPP through the Cogeneration Act alone would result in very high surcharge rates. In order to achieve the 25 % cogeneration target by 2020, cogenerated power production would have to be increased considerably compared to the current prognosis. Roughly speaking, additional new plants with approx.
10 GW capacity and corresponding development of heat sinks would be needed in order to attain the target. The existing cap in the Cogeneration Act would need to be raised considerably in order to implement the newbuilds needed. Changes to the market situation in the next few years or other political action (such as capacity elements) might improve the economics of new cogeneration projects and thus reduce the necessary cogeneration subsidy.

Only some existing CHPP for general supply are still economically viable. Coal-fired plants still have a positive contribution margin 2 in the next few years. Thus no loss is reported from operation of the plants (disregarding capital costs). Natural gas-fired CHPP are not economically viable at present. The annual losses reported by these plants will probably increase still further over the next few years due to very low electricity prices. Unless the prospects of these plants improve they may well have to be shut down. Further expansion of district heating networks is uncertain given the high proportion of natural gas in district heating.

7.7.3 Cogeneration, trigeneration and ORC plants in industry

Industrial cogeneration presents a different picture. The longer the run-time and the higher the rate of private use of electricity by the CHPP, the greater the economic advantage may be compared to uncoupled production. If the CHPP operation is predicated more closely on the supply situation on the electricity market (flexibilisation), this may result in much shorter run-times, which adversely affects their average efficiency rating and thus their economic viability. In that sense, more stringent high-efficiency requirements in connection with the necessary flexibilisation of additional cogeneration capacity would tend to be detrimental. However, the economic advantage depends to a large degree on the prices at which undertakings and factories can buy gas and electricity. Newbuild gas and steam turbine plants in the 5 to 20 MW segment, which make the most interesting contribution to the energy economy (as one-off capacity and as flexibilisation plants) and which are used most in energy-intensive industries (especially raw chemicals and paper), are often not economically viable.
That is because energy-intensive undertakings which trade on the electricity exchange often enjoy such considerable relief on electricity and energy tax and the RES levy and thus have such low energy purchase costs that there is now often hardly any profit to be made from new investments in large CHPP.

Undertakings which are not exempt from the RES levy will also need to pay a considerable portion of the RES levy in future as private generators, meaning that often the remaining savings on the RES levy will not make a large enough contribution to their economic viability. A reduction in the levy on electricity purchases for these undertakings would improve the economic viability of CHPP in the branches in question.

CHPP only obtain relief on energy tax up to 2 MW. Equal treatment of small and large CHPP in terms of energy tax would cancel out the incentive to design plants in the 2 to approx. 5 MW segment at just under 2 MW.

The relatively good rate of return on various BHPP capacities bodes well for further dissemination of cogeneration applications in the branches with large potential for growth (e.g. rest of the chemical industry, rest of the economy or automobile manufacture and machine engineering). However, there is
little knowledge of the advantages of cogeneration or trigeneration

in these 'new' application sectors.

7.7.4 Property cogeneration

Higher cogeneration surcharges for surplus power and cogenerated power marketed directly

Energy purchases are subject to numerous levies and duty, network fees and energy tax. Therefore, substituting energy purchases is generally an attractive proposition. This situation has improved considerably over recent years with the new levies and increased RES levy introduced on electricity purchases. By contrast, the remuneration for cogenerated power deliveries, the price of which for CHPP < 2 MW is based on the average EPEX base load price under the Cogeneration Act, has deteriorated considerably. Even the revenue from cogenerated power marketed directly or on the exchange has fallen considerably recently.

In particular, CHPP which do not use the electricity themselves in the property supplied have problems breaking even. This applies in particular to CHPP in the municipal sector, CHPP in public administration and school buildings and the entire residential sector. It therefore makes sense to grant a higher cogeneration surcharge on cogenerated electricity delivered to the public network.

Conversion of subsidy period for the lowest capacity class to operating hours rather than years

Usually, CHPP receive a subsidy over a period of 30 000 hours' full load operation in the form of cogeneration surcharges. Small CHPP < 50 kW may receive subsidies over 10 years. This means that small CHPP with long annual run-times profit especially from this annual rule. A CHPP with 50 kW electrical capacity and 7 500 hours' full load operation a year receives much higher cogeneration surcharge payments over the 10-year subsidy period than, for example, a 100-kW plant with the same annual run-time. This is due primarily to the fact that the subsidy for the 100-kW plant is only granted for 30 000 hours' full load operation.

However, that does not specifically mean that CHPP with capacity of 50 kW are especially economically viable. Economic viability depends enormously on the property supplied. The economic viability calculation carried out in this study illustrated, for example, that a 50-kW plant supplying a school with heat and power is not particularly economically viable due to the small number of hours' operation. In theory it would appear to make sense to apply longer-term subsidies due to the higher specific investment and integration costs in the lowest capacity segment.

On the other hand, CHPP with a high number of hours' full load operation a year profit in particular from a subsidy predicated on years' operation and, in most cases, they exhibit good economic viability for that reason. We often see in planning practice that CHPP are deliberately sized down in order to achieve the economic optimum with a 50-kW plant with a large number of hours' full load operation and higher subsidy.

In order to limit above-average subsidisation of CHPP < 50 kW with very long run-times, we suggest that **a subsidy based on operating hours should be introduced** in lieu of a subsidy period of 10 years. A subsidy period of 60 000 hours' full load operation, for example, would appear appropriate.

For administrative reasons, the maximum subsidy period should continue to be capped at 15 years. If the 60 000 hours' full load operation have not been completed after 15 years, the subsidy will end nonetheless at the end of the 15 years. That rule would profit all plants up to 6 000 operating hours a year, compared to the rule to date. All CHPP < 50 kW which operate for more than 6 000 hours' full load operation a year would receive fewer cogeneration surcharges compared to the system in force at present. This would prevent false incentives to design small-sized plants.

Flat-rate payments for plants up to 2 kW

Section 7(3) of the current Cogeneration Act allows operators of micro-CHPP with electrical capacity < 2 kW to arrange to be paid an advance flat-rate supplement for cogenerated electricity at the request of the network operator. This rule is applied by around one-third of applicants in this capacity segment.

We recommend that the flat-rate one-off payment should be maintained, in order to keep the transactions costs low for this capacity class.

Preliminary notice in the event of measures to modernise large-capacity CHPP

The Cogeneration Act makes provision in the case of new installations and modernisation measures for approval following commissioning. In practice, determining the 'new investment' on which the pro rata modernisation rate is based is problematic in the event of modernisation. This may cause uncertainty among BHPP operators, as they cannot obtain legally reliable information from the implementing authority as to whether the notified pro rata modernisation rate of 25 % or 50 % will also be recognised in connection with the planned measures. In order to guarantee investment security in the case of modernisation measures, it would make sense to introduce a preliminary notice, at least for large plant capacities.

Abolition of capacity limit for retrofitting

The current limitation on subsidies for retrofitting (Section 5(4) of the 2012 Cogeneration Act) for plants > 2 MW means that the scope of that rule is very limited. Small industrial plants and retrofitting of steam turbines or steam motors with electrical capacity of several hundred kilowatts fall down the subsidy gap. Aside from this existing cogeneration potential, even the implementation of mini-CHPP by adding a power production unit to an existing small boiler system would be conceivable in the medium term. We therefore recommend that the capacity limitation be abolished completely for retrofitting.

Abolition of capacity limit CHPP under the Greenhouse Gas Emissions Trading Act

Since 2008, operators of CHPP installed in a property supplied with installed combustion heat capacity of over 20 MW were obliged to participate in emissions trading. In order to compensate for the impact of the 3rd trading period since 2013, the 2012 Cogeneration Act makes provision for cogeneration surcharge rates to be increased by 0.3 cent/kWh. However, this rule only applies to CHPP > 2 MW capacity.

In reality, CHPP < 2 MW are fitted in properties supplied which are subject to the Greenhouse Gas Emissions Trading Act. Like CHPP > 2 MW electrical capacity, those CHPP are subject to the requirements of the third trading period, but receive no financial compensation in return. It would therefore appear to make sense to abolish the 2 MW capacity limit.

7.7.5 Networks and storage facilities

Subsidisation of heating and cooling networks and heat and cooling storage facilities should be maintained. According to expansion and current projects for heat storage facilities, the storage volume is clustered across large storage facilities in the 30 000 to 45 000 m³ segment. With larger storage facilities and higher overall costs, the pro rata subsidy falls, as each project is subsidised up to a maximum of EUR 5 million.

It makes sense in larger district heating systems to have larger heat storage facilities so that cogeneration can be used as flexibly as possible. Also, the larger the storage facility, the lower the specific costs. Increasing the subsidy threshold to EUR 10 million per project might result in better sized heat storage facilities.

7.7.6 Additional measures to subsidise cogeneration outside the scope of the Cogeneration Act

The current situation of CHPP active on the electricity market suggests that a sufficiently high CO_2 price is an essential basis for the economic success of this efficiency technology on the electricity market. As a result of the collapse in prices for

CO_2 certificates, the CO_2 price has currently lost its politically motivated control function. In order to pursue a successful climate policy, the CO_2 price urgently needs to be increased in the short term, stabilised at a sufficiently high level and then increased again in the long term.

Politicians need to act at European level to obtain a sustainable reduction in the emission budget in the European ETS. A sustainable price effect can only be expected if certificates are suspended. Moreover, action should be taken to ensure equal treatment of heat supplied by CHPP in the ETS and heat supplied by decentralised heating systems which have no CO_2 costs. In the short term, this could be achieved through free allocation of certificates for the provision of heat or fuel-specific supplements on surcharge payments.

The authors also recommend that both plant contracting be investigated for inhibitive and unused support factors and that information be obtained on alternative financing models, as many undertakings tend to finance energy efficiency investments from cash flow and the cogeneration option is then quickly forgotten.

The above recommendations also apply where waste heat is used in ORC plants and the cogeneration application is used for trigeneration, together with:

- the recommendation for a five-year comfort letter for waste heat projects in which a third party finances and operates the ORC plant (contracting). This should enable experience to be acquired in assessing the risk of such projects and the continuity of the waste heat source in order to make such investments accessible to loss insurance by insurance companies. A comfort letter might also improve the attractiveness of contracting projects for other CHPP projects;
- the recommendation that a temporary subsidy for absorption plants be developed (e.g. in the cross-sectional technology support scheme) for operators of trigeneration plants, in addition to the existing subsidy for CHPP.

As industrial CHPP operators, especially those in branches in which cogeneration is less developed, also have potential for flexible power and heat demand, the ability to tax a third party CHPP via electronic communication should also be an eligibility criterion. That is because, depending on the remuneration and frequency of minute and hour reserves, the rate of return on the CHPP can be improved by correspondingly flexible operation of production plants and the CHPP.

As many undertakings that operate or wish to invest in a smaller CHPP are unaware of flexible operation, the authors recommend an information and further training programme here too, that could be integrated as an additional module in the aforementioned information and further training programme. Moreover, this should be a module in the exchange programme and in initial advice to undertakings wanting to participate in an energy efficiency network.

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9 Annex

9.1 Additional information on Chapter 4

9.1.1 Common basic conditions

Table 63: Natural gas retail price by customer group and consumption up to 2050, real, gross calorific value, net of VAT, taxes and duty

		2014	2020	2030	2040	2050
Households, < 55 500 kWh	Cent2013/kWh	4.8	5.4	5.6	6.0	5.9
CTS 1, < 55 500 kWh	Cent2013/kWh	4.6	5.3	5.5	5.7	5.9
CTS 2, > 55 555 kWh	Cent2013/kWh	4.3	5.0	5.2	5.4	5.6
Industry 1, < 277 MWh	Cent2013/kWh	4.4	5.1	5.2	5.3	5.4
Industry 2, < 2.7 MWh	Cent2013/kWh	4.2	4.9	5.0	5.1	5.2
Industry 3, < 27.7 GWh	Cent2013/kWh	3.8	4.5	4.6	4.7	4.8
Industry 4, < 278 GWh	Cent2013/kWh	3.2	3.9	4.0	4.1	4.2
Industry 5, < 1 111 GWh	Cent2013/kWh	2.8	3.5	3.6	3.7	3.8
Industry 6, < 1 111 GWh	Cent2013/kWh	2.6	3.3	3.4	3.5	3.6

Source: Prognos based on Eurostat

Table 64: Breakdown of and changes in electricity prices for households and commercial customers

	2010	2011	2012	2013	2014	2020	2030	2040	2050
Households, 3 500 kWh per annum (incl. VAT)									
Procurement	5.6	5.0	5.1	4.7	4.2	4.3	6.8	8.5	9.1
Distribution	1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Network user fee	5.8	5.9	6.0	6.1	6.2	6.8	7.0	7.2	7.3
RES levy	2.2	3.7	3.7	5.3	6.1	6.7	3.5	1.5	0.8
Cogeneration levy	0.1	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Concession charges	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Electricity tax	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Other levies	0.0	0.0	0.2	0.6	0.4	0.4	0.4	0.4	0.4
Total net (excl. VAT).	19.1	19.9	20.3	22.2	22.4	23.7	23.2	23.1	23.1
Total gross (incl. VAT)	**22.7**	**23.7**	**24.2**	**26.4**	**26.7**	**28.2**	**27.6**	**27.5**	**27.5**
CTS 1: Services industry, 50 MWh per annum, low-voltage level (excl. VAT, without electricity tax relief)									
Procurement	4.4	5.0	4.9	4.1	3.8	4.1	6.6	8.2	8.7
Distribution	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Network user fee	5.0	5.1	5.2	5.3	5.4	6.0	6.1	6.3	6.5
RES levy	2.2	3.7	3.7	5.3	6.1	6.7	3.5	1.5	0.8
Cogeneration levy	0.1	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Concession charges	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Electricity tax	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	0.0
Other levies	0.0	0.0	0.2	0.6	0.4	0.4	0.4	0.4	0.4
Total net (excl. VAT)	**15.9**	**18.0**	**18.2**	**19.6**	**20.1**	**21.6**	**21.0**	**20.8**	**18.7**
CTS 2: Retail trade, 200 MWh per annum, low-voltage level (excl. VAT, without electricity tax relief)									
Procurement	4.4	5.0	4.9	4.1	3.8	4.1	6.6	8.2	8.7
Distribution	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Network user fee	5.0	5.1	5.2	5.3	5.4	6.0	6.1	6.3	6.5
RES levy	2.2	3.7	3.7	5.3	6.1	6.7	3.5	1.5	0.8
Cogeneration levy	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Concession charges	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Electricity tax	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Other levies	0.0	0.0	0.2	0.6	0.4	0.4	0.4	0.4	0.4
Total net (excl. VAT)	**15.7**	**17.8**	**18.0**	**19.3**	**19.8**	**21.3**	**20.7**	**20.5**	**20.4**

CTS 2a: School, 200 MWh per annum, low-voltage level (incl. VAT, without electricity tax relief)									
Procurement	4.4	5.0	4.9	4.1	3.8	4.1	6.6	8.2	8.7
Distribution	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Network user fee	5.0	5.1	5.2	5.3	5.4	6.0	6.1	6.3	6.5
RES levy	2.2	3.7	3.7	5.3	6.1	6.7	3.5	1.5	0.8
Cogeneration levy	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Concession charges	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Electricity tax	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Other levies	0.0	0.0	0.2	0.6	0.4	0.4	0.4	0.4	0.4
Total net (excl. VAT).	15.7	17.8	18.0	19.3	19.8	21.3	20.7	20.5	20.4
Total gross (incl. VAT)	**18.6**	**21.2**	**21.4**	**23.0**	**23.5**	**25.4**	**24.6**	**24.4**	**24.3**
CTS 3: Hospital, 1000 MWh per annum, medium-voltage level (incl. VAT, without electricity tax relief)									
Procurement	4.4	5.0	4.9	4.1	3.8	4.1	6.6	8.2	8.7
Distribution	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Network user fee	3.1	3.1	3.2	3.3	3.4	3.9	4.0	4.1	4.2
RES levy	2.2	3.7	3.7	5.3	6.1	6.7	3.5	1.5	0.8
Cogeneration levy	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Concession charges	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Electricity tax	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Other levies	0.0	0.0	0.2	0.6	0.4	0.4	0.4	0.4	0.4
Total net (excl. VAT).	13.4	15.6	15.7	17.0	17.4	18.8	18.1	17.9	17.8
Total gross (incl. VAT)	**15.9**	**18.6**	**18.7**	**20.2**	**20.7**	**22.4**	**21.6**	**21.3**	**21.1**

Source: Prognos 2014

Table 65: Breakdown of and changes in electricity retail prices for industrial customers

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2030**	**2040**	**2050**
IND 1: Small business, 50 MWh per annum, low-voltage level (excl. VAT, with electricity tax relief)										
Procurement	4.4	5.0	4.9	4.1	3.8	3.9	4.1	6.6	8.2	8.7
Distribution	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Network user fee	5.0	5.1	5.2	5.3	5.4	5.5	6.0	6.1	6.3	6.5
RES levy	2.2	3.7	3.7	5.3	6.1	6.0	6.7	3.5	1.5	0.8
Cogeneration levy	0.1	0.0	0.1	0.2	0.2	0.3	0.2	0.2	0.2	0.2
Concession charges	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Electricity tax	1.6	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Other levies	0.0	0.0	0.2	0.6	0.4	0.4	0.4	0.4	0.4	0.4
Total net (excl. VAT)	**15.2**	**17.8**	**17.9**	**19.3**	**19.8**	**19.9**	**21.3**	**20.7**	**20.5**	**20.5**
IND 2: SME, 200 MWh per annum, low-voltage level (excl. VAT, with electricity tax relief)										
Procurement	4.4	5.0	4.9	4.1	3.8	3.9	4.1	6.6	8.2	8.7
Distribution	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Network user fee	5.0	5.1	5.2	5.3	5.4	5.5	6.0	6.1	6.3	6.5
RES levy	2.2	3.7	3.7	5.3	6.1	6.0	6.7	3.5	1.5	0.8
Cogeneration levy	0.1	0.0	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1
Concession charges	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Electricity tax	1.3	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Other levies	0.0	0.0	0.2	0.6	0.4	0.4	0.4	0.4	0.4	0.4
Total net (excl. VAT)	**14.7**	**17.2**	**17.3**	**18.7**	**19.1**	**19.2**	**20.7**	**20.1**	**19.9**	**19.8**
IND 3: SME, 1000 MWh per annum, medium-voltage level (excl. VAT, with electricity tax relief)										
Procurement	4.4	5.0	4.9	4.1	3.8	3.9	4.1	6.6	8.2	8.7
Distribution	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Network user fee	3.1	3.1	3.2	3.3	3.4	3.4	3.9	4.0	4.1	4.2
RES levy	2.2	3.7	3.7	5.3	6.1	6.0	6.7	3.5	1.5	0.8
Cogeneration levy	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Concession charges	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Electricity tax	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.6	1.6	1.6
Other levies	0.0	0.0	0.2	0.6	0.4	0.4	0.4	0.4	0.4	0.4
Total net (excl. VAT)	**12.0**	**14.3**	**14.4**	**15.7**	**16.1**	**16.1**	**17.5**	**17.4**	**17.1**	**17.0**
IND 4: Industrial plant, 10000 MWh per annum, medium-voltage level (excl. VAT, with electricity tax relief, with peak adjustment)										
Procurement	4.4	5.0	4.9	4.1	3.8	3.9	4.1	6.6	8.2	8.7
Distribution	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Network user fee	3.1	3.1	3.2	3.3	3.4	3.4	3.9	4.0	4.1	4.2

RES levy	2.2	3.7	3.7	5.3	6.1	6.0	6.7	3.5	1.5	0.8
Cogeneration levy	0.05	0.03	0.05	0.05	0.05	0.05	0.05	0.0	0.0	0.0
Concession charges	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity tax	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9
Other levies	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total net (excl. VAT)	**10.9**	**13.2**	**13.1**	**14.0**	**14.6**	**14.6**	**16.0**	**15.5**	**15.2**	**15.1**

Source: Prognos 2014

Table 66: Breakdown of and changes in electricity retail prices for industrial customers, extrapolation

	2010	2011	2012	2013	2014	2020	2030	2040	2050
IND 5: (energy-intensive industry), 100000 MWh per annum, high-voltage level									
Procurement	4.5	5.1	4.2	3.6	3.6	4.0	6.4	7.9	8.3
Distribution	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Network user fee	1.5	1.6	1.6	1.7	1.7	1.9	2.0	2.0	2.1
RES levy	2.2	3.7	3.7	5.3	6.1	6.7	3.5	1.5	0.8
Cogeneration levy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concession charges	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity tax	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Other levies	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total net (excl. VAT)	**8.5**	**10.8**	**9.9**	**11.0**	**11.9**	**13.1**	**12.3**	**11.9**	**11.6**
IND 6: (energy-intensive industry), 100000 MWh per annum, high-voltage level									
(excl. VAT, with electricity tax relief, with peak adjustment, with compensation scheme with retention under Section 41 RES Act)									
Procurement	4.5	5.1	4.2	3.6	3.6	4.0	6.4	7.9	8.3
Distribution	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Network user fee	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4
RES levy	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Cogeneration levy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concession charges	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity tax	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Other levies	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total net (excl. VAT)	**5.2**	**6.0**	**5.0**	**4.5**	**4.5**	**4.9**	**7.3**	**8.8**	**9.2**
IND 7: (energy-intensive industry), 1000000 MWh per annum, high-voltage level									
(excl. VAT, with electricity tax relief, with peak adjustment, with compensation scheme with retention under Section 41 RES Act)									
Procurement	4.5	5.1	4.2	3.6	3.6	4.0	6.4	7.9	8.3
Distribution	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Network user fee	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
RES levy	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Cogeneration levy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concession charges	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity tax	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Other levies	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total net (excl. VAT)	**4.9**	**5.6**	**4.7**	**4.1**	**4.1**	**4.5**	**6.9**	**8.4**	**8.8**

Source: Prognos 2014

Table 67: Electricity retail prices by customer group and consumption up to 2050, except for households, schools (CTS 2a) and hospitals (CTS 3), net of VAT

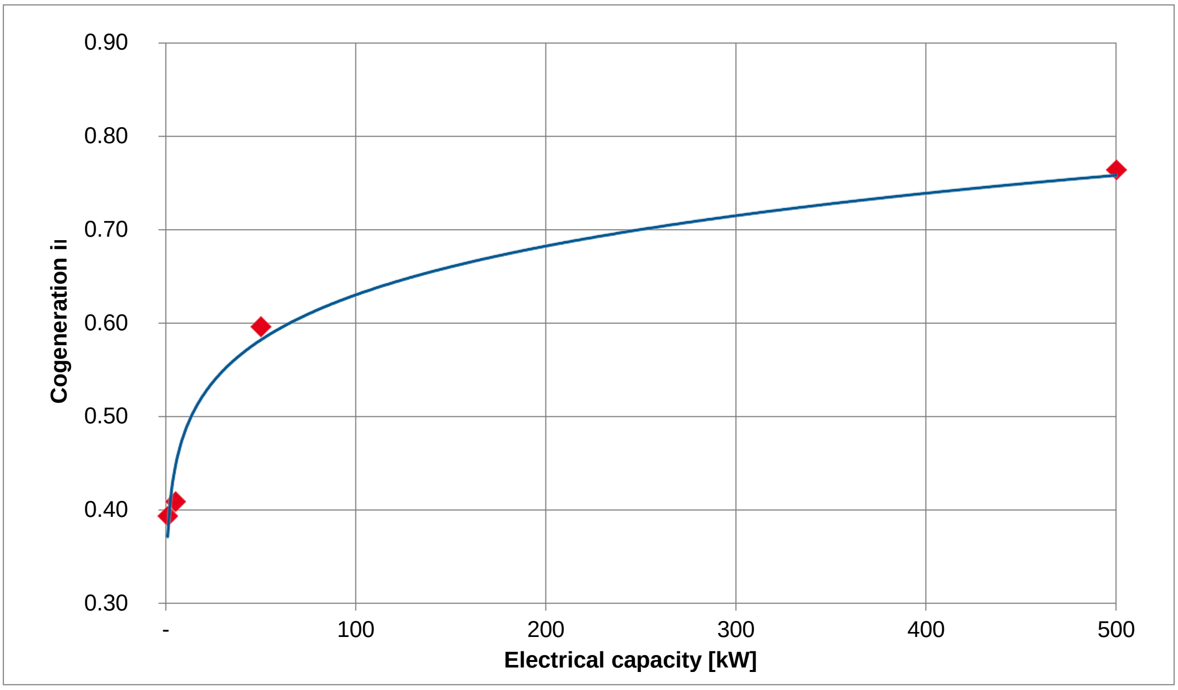
Customer group		**Network level**	**2014**	**2020**	**2030**	**2040**	**2050**
Households (incl. VAT) 3.500 kWh per annum	Cent2013/kWh	LV	26.7	28.2	27.6	27.5	27.5
CTS 1 (services industry), 50 MWh per annum	Cent2013/kWh	LV	20.1	21.6	21.0	20.8	18.7

CTS 2, (retail trade), 200 MWh per annum	Cent2013/kWh	LV	19.8	21.3	20.7	20.5	20.4
CTS 2a, (school, incl. VAT), 200 MWh per annum	Cent2013/kWh	LV					
CTS 3, (hospital, incl. VAT), 1000 MWh per annum	Cent2013/kWh	MV	20.7	22.4	21.6	21.3	21.1
Industry 1, (small business) 5 MWh per annum	Cent2013/kWh	LV	19.8	21.3	20.7	20.5	20.5
Industry 2, (SME), 200 MWh per	Cent2013/kWh	LV	19.1	20.7	20.1	19.9	19.8
Industry 3, (SME), 1000 MWh per annum	Cent2013/kWh	MV	16.1	17.5	17.4	17.1	17.0
Industry 4, (industrial plant), 10000 MWh per annum	Cent2013/kWh	MV	14.6	16.0	15.5	15.2	15.1
Industry 5, (industrial plant), 100000 MWh per annum	Cent2013/kWh	HV	12.1	13.2	12.4	12.0	11.8
Industry 6, (energy-intensive industry), 100000 MWh per annum, reduced network fee	Cent2013/kWh	HV	4.7	5.1	7.5	9.0	9.4
Industry 7, (energy-intensive industry), 1000 GWh per annum, reduced network fee	Cent2013/kWh	HV	4.3	4.7	7.1	8.6	9.0

Source: Prognos

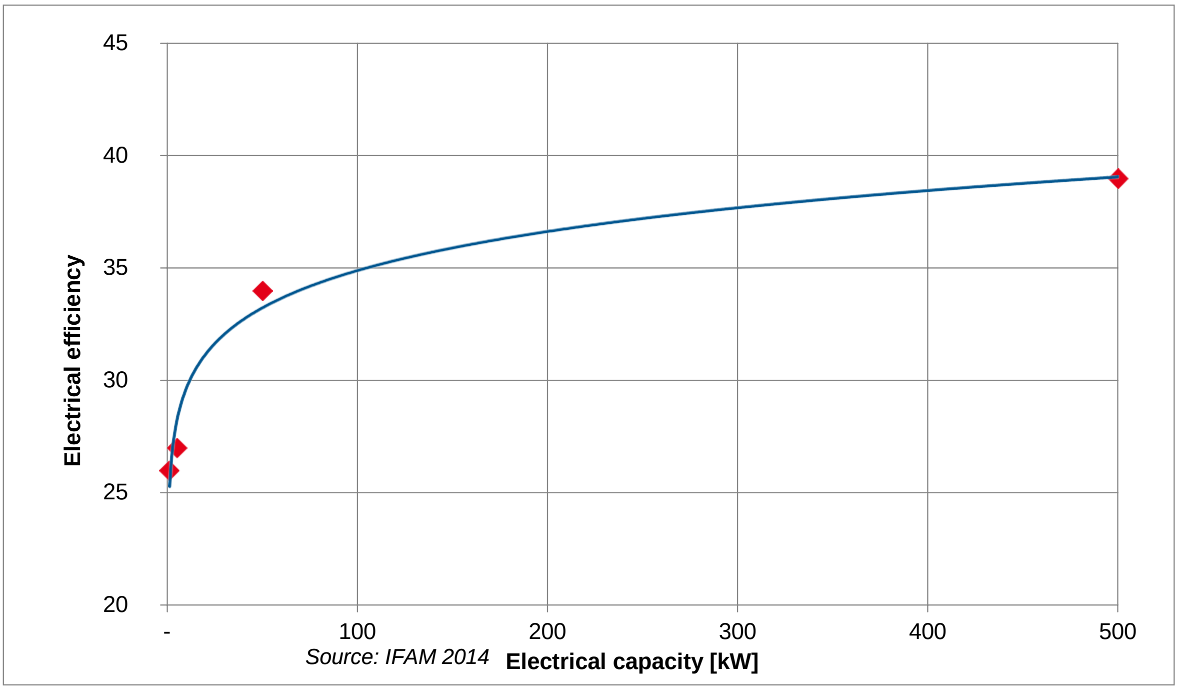
9.1.2 Private households and CTS

Figure 61: Compensation function of cogeneration index of BHPP



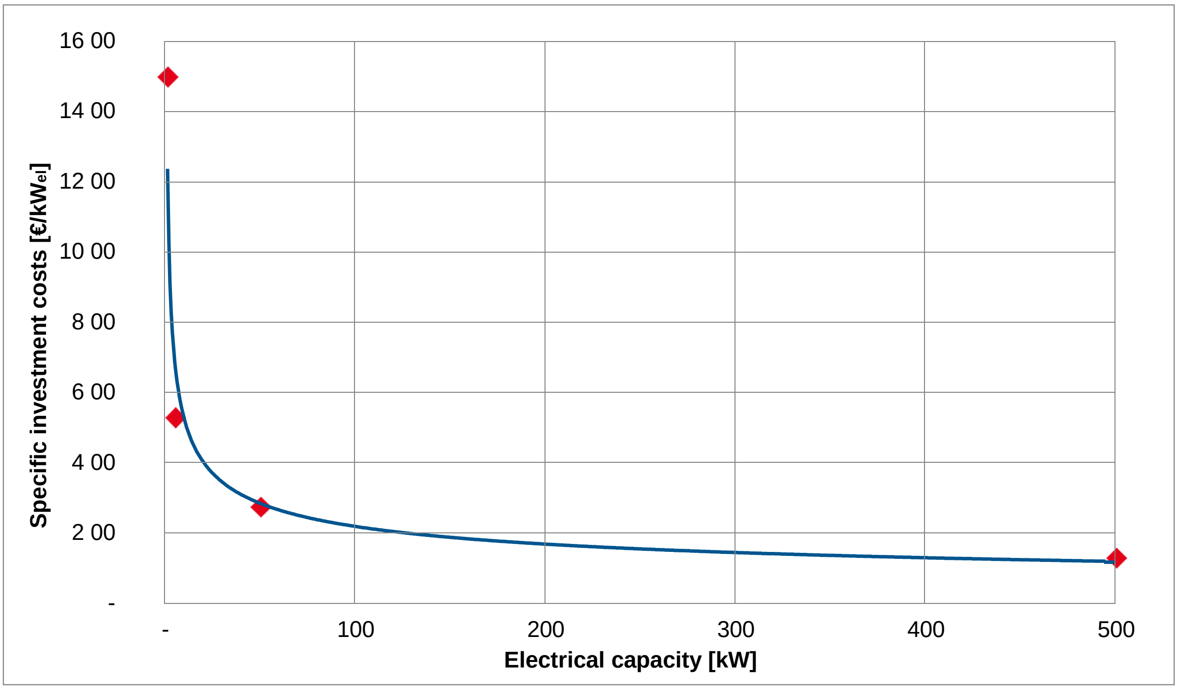
Source: IFAM 2014

Figure 62: Compensation function of electrical efficiency of BHPP



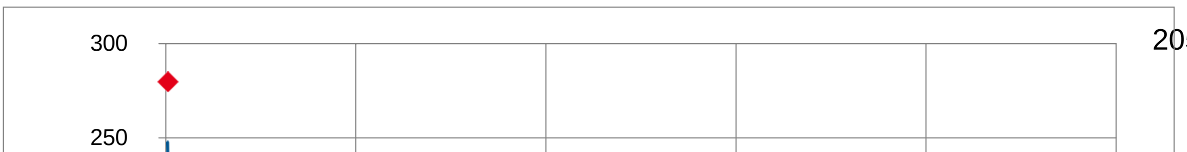
Source: IFAM 2014

Figure 63: Compensation function of specific investment sums of BHPP



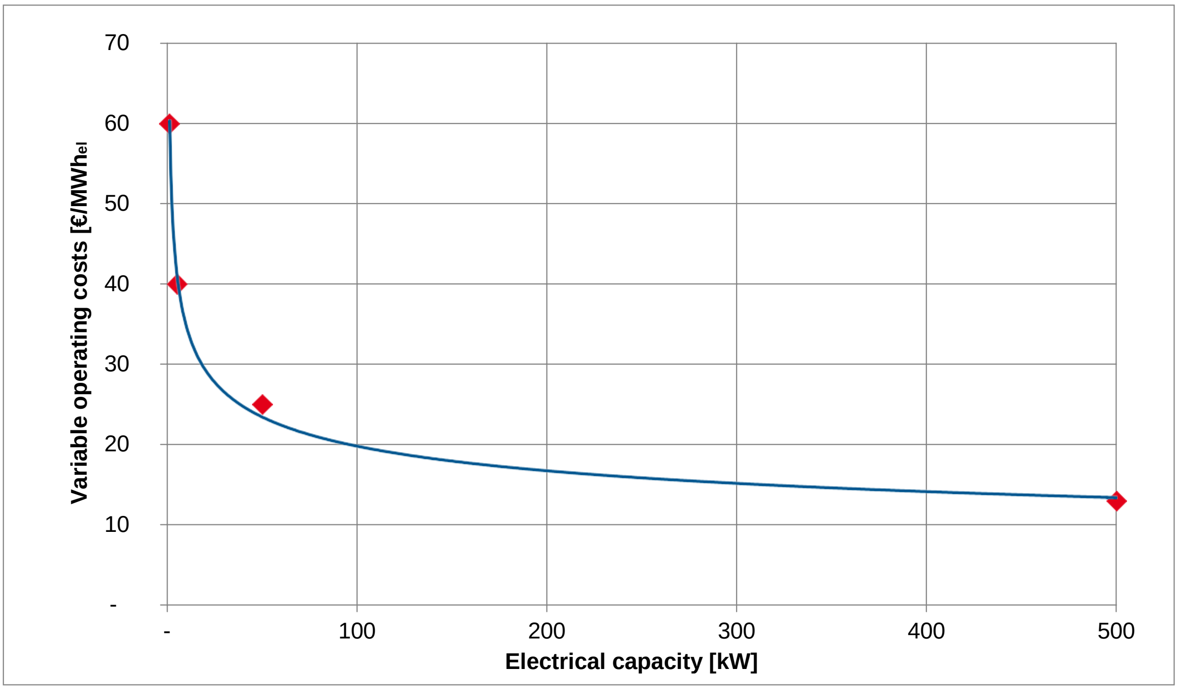
Source: IFAM 2014

Figure 64: Compensation function of fixed operating costs of BHPP



Source: IFAM 2014

Figure 65: Compensation function of variable operating costs of BHPP



Source: IFAM 2014

Table 68: Building and plant parameters for OFH

Type of building and year of	Unit	MOT 1969	OFH 1958	OFH 1969	EOT 1969
Useful energy requirement	MWh/a	20.4	25.4	33.3	36.7

Peak load	kW	10.9	13.5	17.7	19.5
Rate of private electricity use		50 %	50 %	50 %	50 %
Full load hours cogeneration	h/a	4 500	4 500	4 500	4 500
Proportion of cogenerated heat		60 %	60 %	60 %	60 %
Thermal capacity BHKW as % of peak load		25 %	25 %	25 %	25 %
Cogenerated thermal capacity	kWth	2.7	3.4	4.4	4.9
Cogeneration index		0.37	0.38	0.40	0.40
Electrical capacity BHPP	kWel	1.0	1.3	1.8	2.0
Efficiency el.	%Hi	25.3 %	25.8 %	26.3 %	26.5 %
Investment costs incl. planning costs	€2013/kWel	12 316	11 230	10 000	9 598
Fixed operating costs	€2013/(kWel a)	246	219	189	179
Variable operating costs	€2013/MWhel	60	57	53	51
Gas-fired boiler supply option	kW	10.9	13.5	17.7	19.5
Interest rate (economic pers.)		3.0 %	3.0 %	3.0 %	3.0 %
Interest rate (business pers.)		6.0 %	6.0 %	6.0 %	6.0 %

Sources: (IWU 2013), IFAM 2014

Table 69: Building and plant parameters for AB (Part 1/2)

Type of building and year of construction	**Unit**	**AB 1979**	**AB pre-1948**	**AB 1958**	**AB 1949**
Useful energy requirement	MWh/a	54.9	71.6	74.6	78.0
Peak load	kW	23.5	30.7	32.0	33.5
Rate of private electricity use		10 %	10 %	10 %	10 %
Full load hours cogeneration	h/a	5 000	5 000	5 000	5 000
Proportion of cogenerated heat		64 %	64 %	64 %	64 %
Thermal capacity BHKW as % of peak load		30 %	30 %	30 %	30 %
Cogenerated thermal capacity	kWth	7	9	10	10
Cogeneration index		0.42	0.44	0.44	0.44
Electrical capacity BHPP	kWel	3.0	4.0	4.2	4.4
Efficiency el.	%Hi	27 %	28 %	28 %	28 %
Investment costs incl. planning costs	€2013/kWel	8 209	7 333	7 206	7 070
Fixed operating costs	€2013/(kWel a)	147	127	125	122
Variable operating costs	€2013/MWhel	46	43	43	42
Gas-fired boiler supply option	kW	23.5	30.7	32.0	33.5
Interest rate (economic pers.)		3.0 %	3.0 %	3.0 %	3.0 %
Interest rate (business pers.)		6.0 %	6.0 %	6.0 %	6.0 %

Source: (DENA 2012), IFAM 2014

Table 70: Building and plant parameters for AB (Part 2/2)

Type of building and year of construction	Unit	LAB pre-1948	LAB 1949	LAB 1958	LAB 1969
Useful energy requirement	MWh/a	190.5	268.8	355.0	410.2
Peak load	kW	81.7	115.3	152.3	176.0
Rate of private electricity use		10 %	10 %	10 %	10 %
Full load hours cogeneration	h/a	5 000	5 000	5 000	5 000
Proportion of cogenerated heat		64 %	64 %	64 %	64 %
Thermal capacity BHKW as % of peak load		30 %	30 %	30 %	30 %
Cogenerated thermal capacity	kW_{th}	25	35	46	53
Cogeneration index		0.50	0.52	0.54	0.55
Electrical capacity BHPP	kW_{el}	12.1	17.9	24.5	28.9
Efficiency el.	$\%_{Hi}$	30 %	31 %	32 %	32 %
Investment costs incl. planning costs	$€_{2013}/kW_{el}$	4 840	4 182	3 716	3 496
Fixed operating costs	$€_{2013}/(kW_{el}\ a)$	75	62	54	50
Variable operating costs	$€_{2013}/MWh_{el}$	33	30	28	27
Gas-fired boiler supply option	kW	81.7	115.3	152.3	176.0
Interest rate (economic pers.)		3.0 %	3.0 %	3.0 %	3.0 %
Interest rate (business pers.)		6.0 %	6.0 %	6.0 %	6.0 %

Source: (DENA 2012), IFAM 2014

Table 71: Building and plant parameters for CTS buildings

Type of building	Unit	Hospital	Office	Commercial
Useful energy requirement	MWh/a	2 000	100	2 000
Peak load	kW	671	79	956
Rate of private electricity use		90 %	40 %	50 %
Full load hours cogeneration	h/a	6 000	4 000	4 500
Proportion of cogenerated heat		60 %	47 %	65 %
Thermal capacity BHKW as % of peak load		30 %	15 %	30 %
Cogenerated thermal capacity	kW_{th}	201	12	287
Cogeneration index		0.65	0.45	0.68
Electrical capacity BHPP	kW_{el}	131	5.4	195
Efficiency el.	$\%_{Hi}$	36 %	28 %	37 %
Investment costs incl. planning costs	$€_{2013}/kW_{el}$	1 980	6 586	1 705
Fixed operating costs	$€_{2013}/(kW_{el}\ a)$	24	111	20
Variable operating costs	$€_{2013}/MWh_{el}$	19	40	17
Gas-fired boiler supply option	kW	671	79	956
Interest rate (economic pers.)		3.0 %	3.0 %	3.0 %
Interest rate (business pers.)		8.0 %	8.0 %	8.0 %

Source: IFAM 2014

Table 72: Thermal insulation measures for OFH

Type of building and year of construction	**Unit**	**MOT 1969**	**OFH 1958**	**OFH 1969**	**EOT 1969**
Useful energy requirement (pre-	MWh/a	20.4	25.4	33.3	36.7
Full load hours, heating load	h/a	1 878	1 878	1 878	1 878
Peak load (pre-renovation)	kW	10.9	13.5	17.7	19.5
Existing plant technology		Low-temperature	Low-temperature	Low-temperature	Low-temperature
Measures					
External wall		Thermal insulation composite system on old stucco during comprehensive and necessary stucco renovation			
Windows		Triple-glazing, plastic frames, standard windows (tilt and turn, no bars)			
Roof		None	Insulation between/on joists during necessary re-roofing, disposal of old insulation between joints		
Top-floor ceiling		Insulation of top-floor ceiling, not accessible, disposal of old insulation		None	None
Cellar ceiling		Insulation on underside of cellar ceiling, no additional protection against mechanical damage			
Energy-related additional costs					
External wall	€	2 974	6 390	8 153	8 813
Windows	€	1 064	1 120	1 456	1 904
Roof	€	0	4 459	6 711	4 961
Top-floor ceiling	€	1 997	1 049	0	0
Cellar ceiling	€	4 974	3 847	3 847	3 143
Total	**K€**	**11.0**	**16.9**	**20.2**	**18.8**
Potential savings (useful energy)					
External wall	kWh/a	1 981	3 860	5 702	6 935
Windows	kWh/a	826	789	1 565	2 167
Roof	kWh/a	0	3 684	3 354	3 179
Top-floor ceiling	kWh/a	2 394	1 667	0	0
Cellar ceiling	kWh/a	2 477	1 667	1 901	1 734
Total	**MWh/a**	**7.7**	**11.7**	**12.5**	**14.0**
Useful energy requirement after	MWh/a	12.71	13.68	20.79	22.68
Peak load after renovation	kW	6.8	7.3	11.1	12.1

Sources: (IWU 2013), IFAM 2014

Table 73: Thermal insulation measures for AB (Part 1/2)

Type of building and year of construction	**Unit**	**AB 1979**	**AB 1958**	**AB 1949**	**AB pre-1948**
Useful energy requirement (pre-	MWh/a	54.9	74.6	78.0	71.6
Full load hours, heating load	h/a	2 331	2 331	2 331	2 331
Peak load (pre-renovation)	kW	23.5	32.0	33.5	30.7
Existing plant technology		Low-temperature oil-fired boiler outside thermal envelope, year of construction 1987-1994		Low-temperature gas-fired boiler outside thermal envelope, year of construction 1987-1994	
Measures					
External wall		Thermal insulation composite system on old stucco, fibre-reinforced new			Thermal insulation
Windows		Triple-glazing, insulated frame (suitable for passive houses)			
Roof		Insulation between and on joints during re-roofing			
Top-floor ceiling		None	None	Insulation, accessible flooring	
Cellar ceiling		Insulation on underside, glued or dowelled			
Energy-related additional costs					
External wall	€	26 374	23 100	24 080	25 256
Windows	€	13 340	16 330	14 720	13 527
Roof	€	9 251	10 036	5 320	3 432
Top-floor ceiling	€	0	0	4 331	4 130
Cellar ceiling	€	4 800	6 32	4 875	4 144
Total	**K€**	**53.8**	**55.8**	**53.3**	**50.5**
Potential savings (useful energy)					
External wall	kWh/a	13 468	16 744	20 643	18 957
Windows	kWh/a	3 492	5 175	4 554	5 093
Roof	kWh/a	2 993	6 393	5 161	2 264
Top-floor ceiling	kWh/a	0	0	3 036	2 546
Cellar ceiling	kWh/a	1 746	4 871	3 947	4 810
Total	**MWh/a**	**21.7**	**33.2**	**37.3**	**33.7**
Useful energy requirement after	MWh/a	33.17	41.40	40.68	37.91
Peak load after renovation	kW	14.2	17.8	17.5	16.3

Source: (DENA 2012), IFAM 2014

Table 74: Thermal insulation measures for AB (Part 2/2)

Type of building and year of construction	**Unit**	**LAB pre-1948**	**LAB 1949**	**LAB 1958**	**LAB 1969**
Useful energy requirement (pre-	MWh/a	190.5	268.8	355.0	410.2
Full load hours, heating load	h/a	2 331	2 331	2 331	2 331

Peak load (pre-renovation)	kW	81.7	115.3	152.3	176.0
Existing plant technology		Low-temperature gas-fired boiler outside thermal envelope, year of construction 1987-1994		District heating from cogeneration	District heating from cogeneration
Measures					
External wall		Thermal insulation composite system on old stucco, fibre-reinforced new			Thermal insulation
Windows		Triple-glazing, insulated frame (suitable for passive houses)			
Roof		None	None	None	Roof renovation
Top-floor ceiling		Insulation, accessible flooring			None
Cellar ceiling		Insulation on underside, glued or dowelled			
Energy-related additional costs					
External wall	€	44 660	63 294	77 824	97 324
Windows	€	43 470	62 100	81 650	105 570
Roof	€	0	0	0	30 540
Top-floor ceiling	€	21 490	31 500	48 860	0
Cellar ceiling	€	10 438	15 300	22 336	16 797
Total	**K€**	**120.1**	**172.2**	**230.7**	**250.2**
Potential savings (useful energy)					
External wall	kWh/a	52 599	50 034	78 516	112 461
Windows	kWh/a	17 864	20 944	25 603	52 923
Roof	kWh/a	0	0	0	19 846
Top-floor ceiling	kWh/a	13 894	38 398	35 844	0
Cellar ceiling	kWh/a	11 909	16 290	18 776	15 436
Total	**MWh/a**	**96.3**	**125.7**	**158.7**	**200.7**
Useful energy requirement after	MWh/a	94.28	143.12	196.29	209.49
Peak load after renovation	kW	40.4	61.4	84.2	89.9

1 Transfer station outside thermal envelope, year of construction 1987-1994

2 New district heating compact station with reduced input; including buffer storage, regulation and pumps; transfer station outside thermal envelope

Source: [DENA 2012], IFAM 2014

Table 75: Basic data of OFH considered

		Gas-fired boiler	Air-water heat pump	Brine-water heat pump (borehole)	Brine-water heat pump (collector)
Heating load	kW	9	9	9	9
Heat requirement	MWh/a	15	15	15	15
Investment costs	€/kW	1 970	2 614	3 399	2 810
Operation-linked costs	€/a	177	195	266	213

Gas/electricity consumption	MWh/a	16	6	5	5
Useful life	a	20	20	20	20

Sources: (ITG 2012), (IER 2001)

Table 76: Basic data of AB considered

		Gas-fired boiler	**Air-water heat pump**	**Brine-water heat pump**
Heating load	kW	20	20	20
Heat requirement	MWh/a	34	34	34
Investment costs	€/kW	1 445	2 008	2 978
Operation-linked costs	€/a	805	846	1 043
Gas/electricity consumption	MWh/a	36	12	11
Useful life	a	20	20	20

Sources: (ITG 2012), (IER 2001)

9.1.3 Industrial cogeneration

There are various empirical sources for the specifications of industrial CHPP plants. They sometimes differ from each other, basically for the following reasons:

- Sometimes the power production efficiency rating is not the net efficiency rating, i.e. it does not correspond to deliveries by the plant to the operating network less the quantities of power required for the plant itself.
- Sometimes they are planning data, sometimes empirical measurements or cost data.
- Sources such as ‘best practices’ or ‘BHPP of the month’ may by definition not be representative; mostly they are very favourable situations.
- Sometimes the annual hours’ use is equated to full load operation or full load hours, even though there may be clear differences here in industry. That is because efficiency rating losses and annual full load operation hours in industrial undertakings are also determined by spot prices for electricity and the CHPP is reduced if the spot price is lower than the costs of private generation. The increased flexibility needed also results in additional investments (extraction condensing turbines, heat storage facilities and more control technology). However, there are no representative data here on current practice in terms of such flexible power production.

Where possible, we tried when compiling the data to take account of and make allowance for the causes of the differing data. Sometimes that too gives rise to alternative assumptions (e.g. in terms of duration of full load operation or private consumption of electricity) or to sensitivity calculations.

The electrical efficiency ratings given in Table 10 are net efficiency rates; although the investment sum includes planning costs, it does not include transaction costs which undertakings often notionally report as overheads but which contractors incur as real costs.

Re: 4.3.2Methodology and energy prices

The economic viability calculations for the six types of plant considered were carried out based on the plant characteristics given in Table 10. The calculation period is equal to the assumed lifetime or typical depreciation period for tax purposes; it increases from 10 years to 15 years *inter alia* as the capacity increases.

Rate of return from a business perspective

The difference between the costs of the energy generated by a CHPP (electricity, heat) compared to the costs for uncoupled/purchased electricity is the only parameter that determines the economic viability of a CHPP.

Costs: Capital costs, fixed and variable operating costs, annual fuel costs (incl. taxes and levies)

Revenue: Cogeneration subsidy, network user fees saved, heat credit

Fuel costs exert by far the biggest influence on power production costs, but may vary considerably depending on consumption. *Per contra*, heat credits (see Table 77) generally make the biggest quantitative contribution to the revenue achieved.

$$Heat\ credit = \frac{thermal, cogeneration}{electrical, cogeneration} * \frac{1}{thermal, boiler} * \mathrm{KBr.}$$

η: thermal or electrical efficiency rating (%)

K_{BR}: Fuel costs (Cent/kWh_{el})

Table 77: Heat credits used for various types of CHP plants/cogeneration capacity levels

Type of plant	Unit	2013
50 kW BHPP	Cent/kWh	8.54
500 kW BHPP		6.64
2 MW BHPP		5.31
5 MW DT		11.15
10 MW GT		6.52

20 MW G&S		5.30

Source: IREES 2014

The cogeneration subsidy must also be taken into account on the revenue side. As it is usually limited in time, it has been apportioned here to the lifetime of the plant for the sake of simplicity.

$$Effective\ subsidy$$

$$= \frac{Cogeneration\ subsidy\ (\frac{cent}{kWh_{el}})}{Cogeneration\ subsidisation\ period\ (a)} * Lifetime$$

Lifetime: technical lifetime in years

The energy prices or saved electricity purchase prices assumed in the calculations for industrial cogeneration do not vary over time; they remain constant at the value in the starting year in question. This simulates the current typical situation of an investor making a decision who does not know how future energy prices will change and thus applies the energy prices at the time of investment consistently across the calculation period used in the economic viability analysis (usually the lifetime of the CHPP calculated).

That stationary approach results in slightly lower rates of return for cogeneration applications than those given in Chapter 7.5, which were calculated with variable energy prices over the calculation period. This dynamic calculation method assumes an investor who knows (and is not wrong about) future energy prices.

Another difference between these and the calculations of the rate of return of cogeneration in Chapter 7.5 is that these calculations are based on a required rate of return of 12 % (and those are based on 8 %). The higher rate reflects standard rates of return expected in industry and risk assessments.

However, blanket conclusions as to the economic viability of CHPP in industry based on typification by capacity and technology can only be drawn to a limited extent. That is because the operating circumstances in terms of individual production structures, the size of the undertaking and the amount and structure of energy consumption may vary enormously within the same branch. In particular, the electricity prices with which private production in a CHPP must compete vary considerably; that is because they are negotiated, with some electricity being purchased through groups or groupings and some being purchased via the exchange.

It is possible to draw relatively sound conclusions as to the electricity production costs of specific technologies based on fundamental parameters such as annual full load hours. The annual full load hours assumed in this study varied across the board from 2 000 h/a to 7 000 h/a, even though plants are not expected as a rule to afford an adequate rate of return at the lower limit. The upper limit represents the best realisable value in practical continuous operation; however, they may be exceeded by way of exception and under favourable conditions in individual operating years.

The power production costs thus obtained then need to be compared case by case with the electricity prices paid by the undertaking in question. To simplify matters, the electricity prices payable by industrial customers were established for seven examples (IND1 TO IND7). They were classed based on annual quantities purchased and assumptions as to the typical network level of the supply point ('network level'), which determines the network user fee.

The facility for electricity-intensive companies to make a claim under the compensation scheme laid down in the RES Act was considered as further difference. To simplify matters, it was assumed that this was only open to IND6 and IND7 (annual quantity purchased > 100 000 MWh at high voltage level).

We basically assumed that industrial customers claim electricity tax relief and tax capping on quantities purchased > 1 000 MWh/a (IND3 to IND7). See also Section 4.1 and Table 11 for individual electricity price components.

That gave the industrial electricity prices listed in Table 11, on which the economic viability analysis comparing power production costs and electricity prices paid was based.

As many large undertakings employ energy traders or use external trading services, the costs of which cannot be taken into account here, one might perhaps disregard the distribution margin as a cost component of the electricity purchases calculated. This would depress the calculated rate of return of CHPP, but only to a small extent, as the distribution margin only accounts for a secondary share of electricity prices.

All calculations for the cost-benefit analysis were carried out based on an exemplary rate of private electricity use of 100 %, even though that may vary enormously depending on the individual characteristics of each undertakings/CHPP. In 2013, there was no pro rata charge on private consumption of electricity in the form of an RES levy; however, that changes in 2020, when a 40 % charge is imposed on the private electricity requirement.

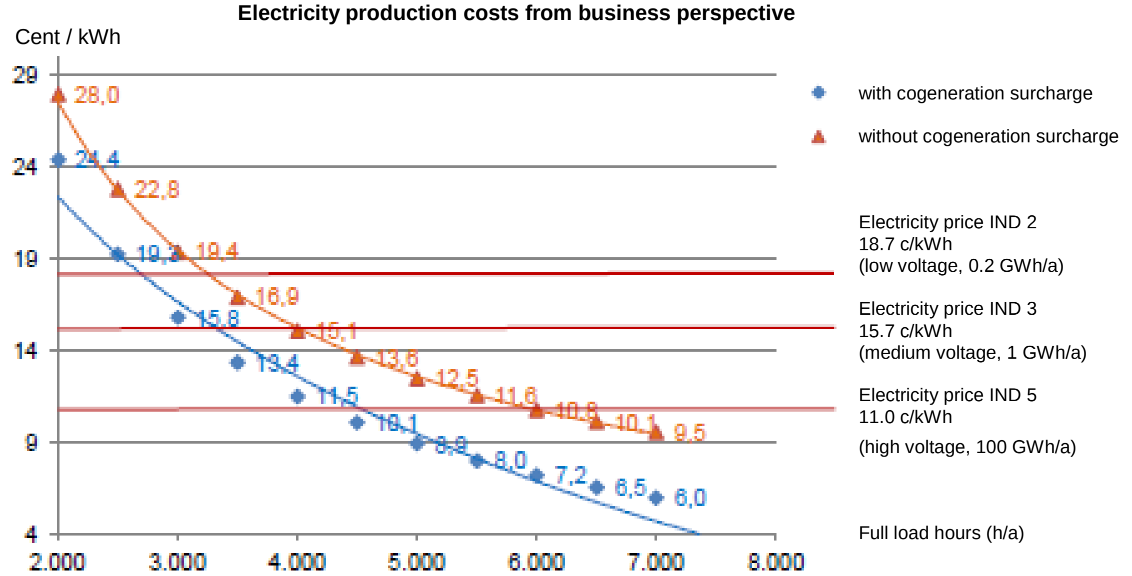
Cost-benefit analysis from economic perspective

The rate of return and power production costs from an economic perspective are defined in this analysis as the residual costs without any tax, duty or (RES and cogeneration) levies. Thus the fuel used has no energy tax and the quantities of electricity purchased have no electricity tax and RES and cogeneration levies are disregarded.

However, that definition of a rate of return from an economic perspective has the disadvantage that changes to the energy system pursued under energy and climate policies towards more renewable energies and cogeneration and the underlying desire to avoid high adaptation costs and damages in future are not taken into account.

Annex to Chapter 4.3.3: Additional results for the economic viability of CHPP

Figure 66: 'Business' electricity production costs of a BHPP with 50 kW$_{el}$ capacity as a function of full load hours in 2013

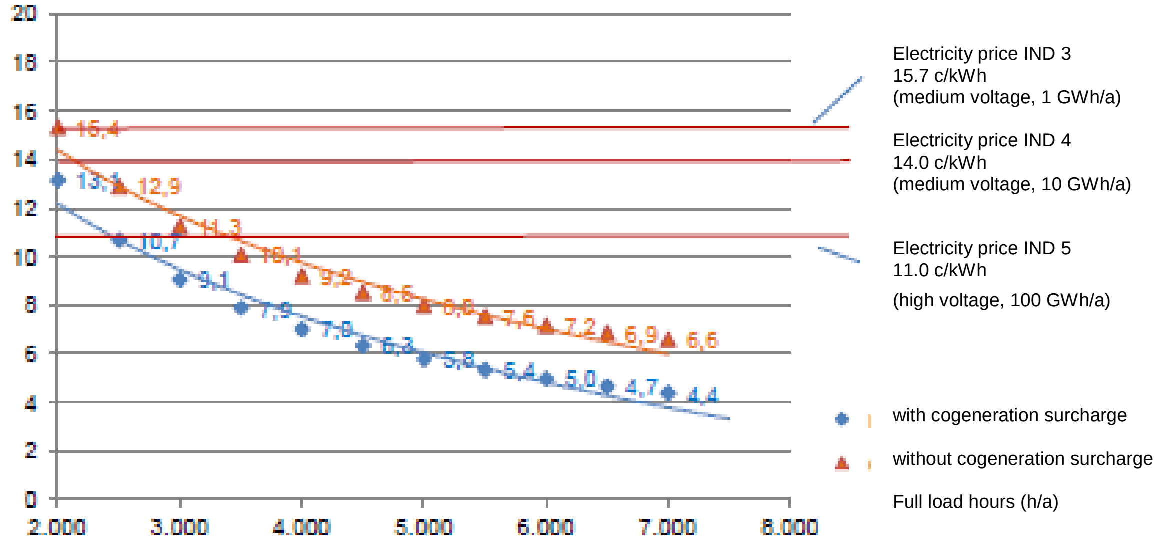


Source: IREES 2014

Figure 67: 'Business' electricity production costs of a BHPP with 500 kW$_{el}$ capacity as a function of full load hours in 2013

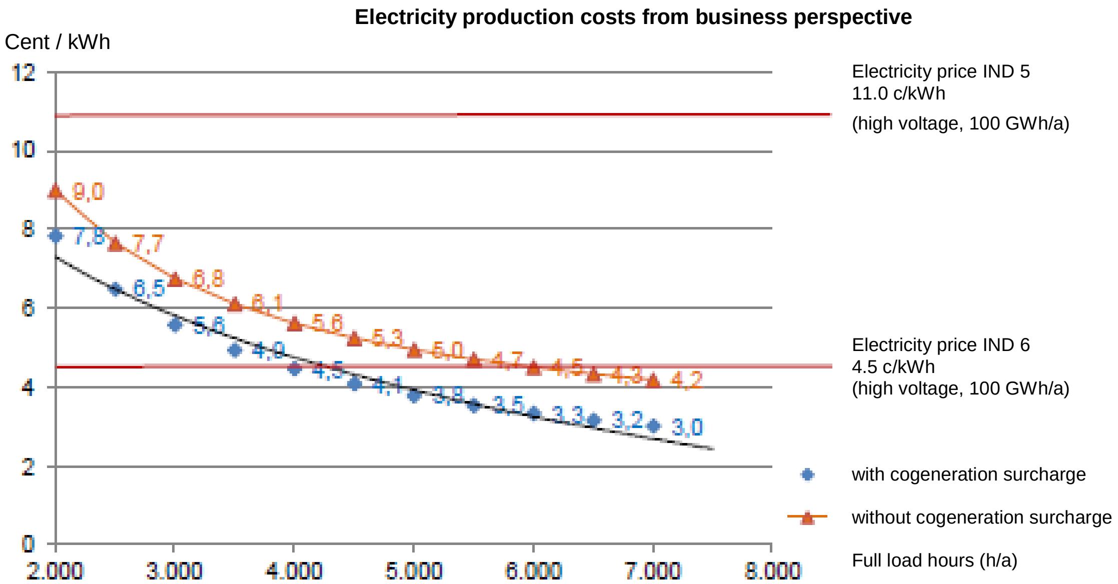
Electricity production costs from business perspective

Cent / kWh



Source: IREES 2014

Figure 68: ‘Business’ electricity production costs of a BHPP with 2 MW_{el} capacity as a function of full load hours in 2013



Source: IREES 2014

Figure 69: ‘Business’ electricity production costs of a steam turbine with 5 MW_{el} capacity as a function of full load hours in 2013

Electricity production costs from business perspective

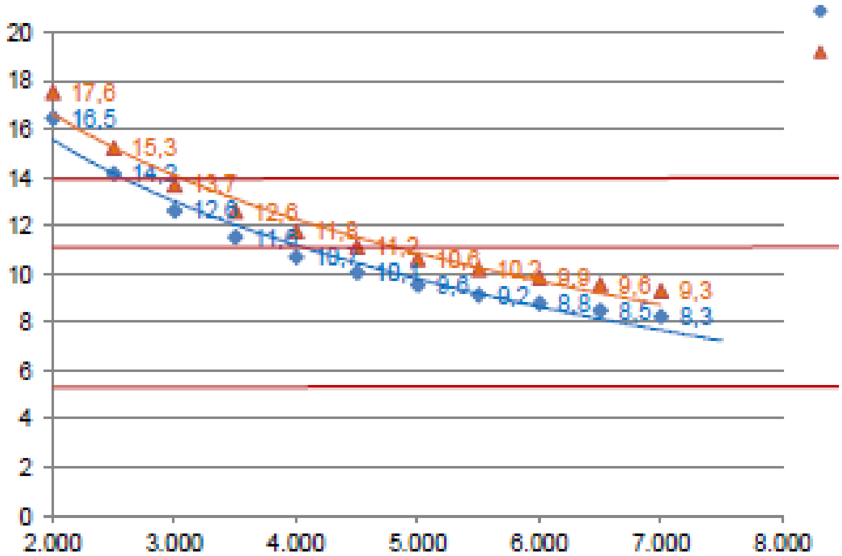
Cent / kWh

with cogeneration surcharge

without cogeneration surcharge

Electricity price IND 4
14.0 c/kWh
(medium voltage, 10 GWh/a)

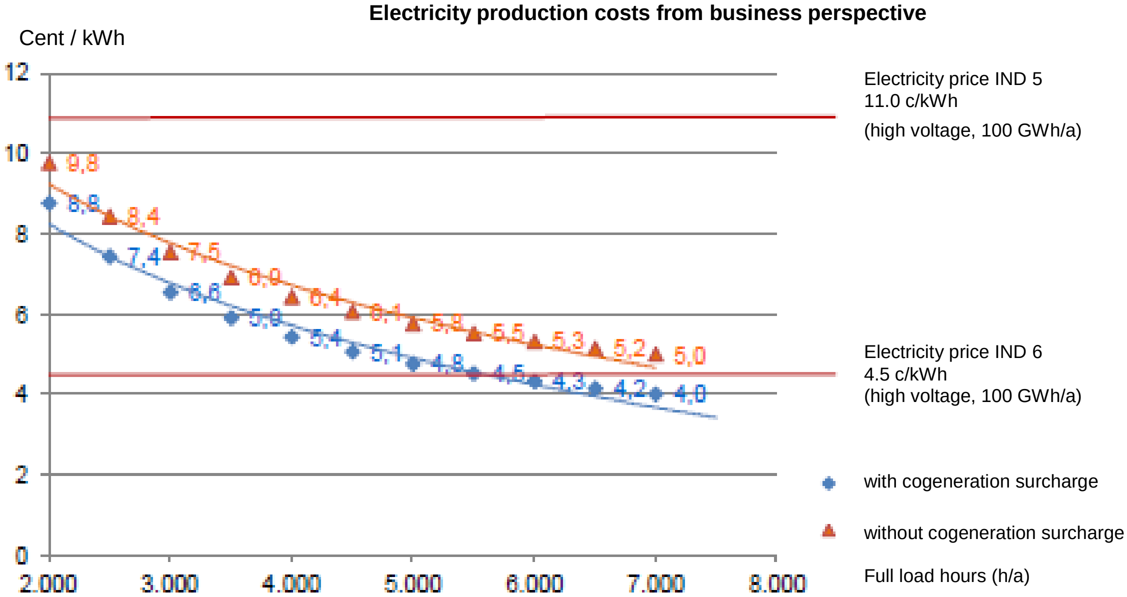
Electricity price IND 5
11.0 c/kWh
(high voltage, 100 GWh/a)



Source: IREES 2014

Figure 70: *'Business' electricity production costs of a gas turbine with 10 MW_{el} capacity as a function of full load hours in 2013*

Electricity production costs from business perspective

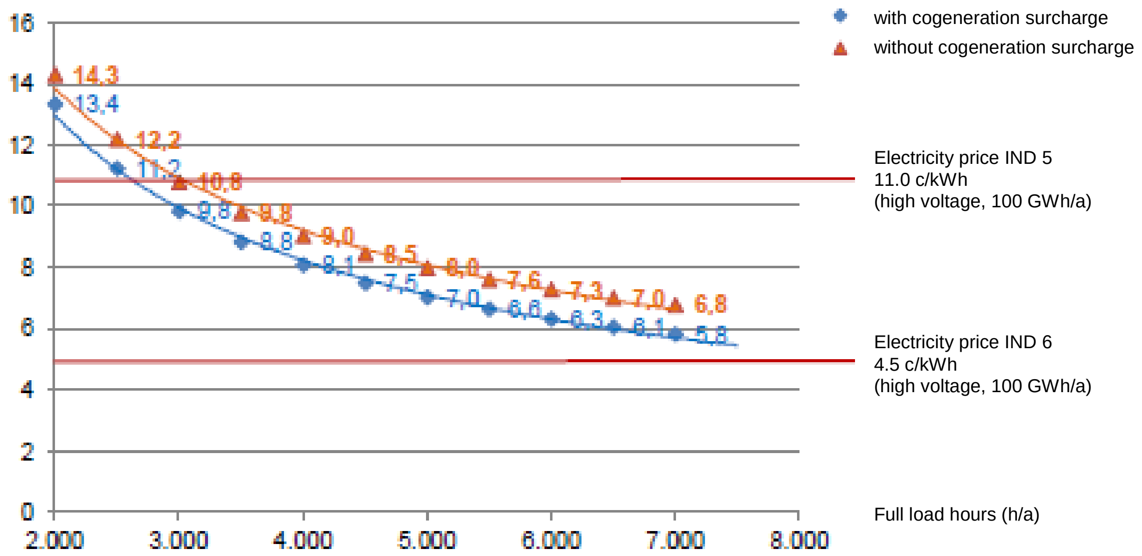


Source: IREES 2014

Figure 71: *'Business' electricity production costs of a gas and steam turbine with 20 MW_{el} capacity as a function of full load hours in 2013*

Electricity production costs from business perspective

Cent / kWh



Source: IREES 2014

9.2 Additional information on Chapter 5 (potential analysis)

9.2.1 Potential determined for the private household and CTS sectors

Table 78: Number of model towns in town categories

Category	Number of model
I	3
II	6
III	6
IV	5
V	9
VI	3
VII	5
VIII	3
IX	1
Total	**41**

Source: IFAM 2014

Table 79: Attributes of individual properties in model towns

Attribute	Description
Heat requirement	There is a heat requirement for each heated building in the model towns, both as an absolute value and as a volume-/area-based value. The data for a town are available at the level of groups of blocks.

Information on type of use	Classification of buildings by type of use is included in the basic geo-data (3D laser scans, ALK, ALKIS) for those towns for which there are individual buildings. The degree of accuracy of the classification varies from one town to another. Characteristics such as the number of buildings for a particular type of use cannot therefore automatically be compared between the towns (see IFAM, 2014).
Base area and height of building	3D laser scanning data can be used for the towns in North Rhine-Westphalia. Information on height for the towns in the other federal states is obtained mostly from the LoD1 models of the federal states or they were included in the heat atlases provided to IFAM.
Number of storeys	Information on the number of storeys in individual buildings is sometimes included in the 3D laser scanning data and LoD1 data. In some projects processed by IFAM, the number of storeys was deduced from the height of the building based on mean ceiling heights. Information on the number of storeys is available for many of the model towns.
Floor space	The floor space is taken as the energy reference space for the towns for which the number of storeys is available. The floor space in the building is calculated as follows: Base area x number of storeys x 0.7 That factor is obtained for the buildings considered as the mean from (BKI, 2010). That area is approximately equal to the living space in residential buildings and the main floor space in non-residential buildings.
Volume of building	If the building height is available, the volume of the building can be deduced from the height and base area of the building.
Age class	As a rule, information on the age class of the individual properties is available for the model towns for which IFAM has prepared a heat atlas.
Length of connection line	The length of the building connection line is determined for each building, assuming that a building connection station is installed. The precise method is documented in (BEI, 2011). The accuracy of the method was successfully validated based on existing networks in various settlement structures. For the towns in which the necessary data are not available, the length of the building connection line was transferred from similar clusters based on mean connection line lengths.
Classification Cluster und Cluster	Each property has a cluster and cluster network identifier (see section 5.1.1.6).
Distribution network length	The distribution network length is compiled at cluster, not individual building level. The same method is used as for the length of the building connection line (BEI, 2011), assuming that the distribution network is laid along the roads within the cluster. For towns for which the road network is not available, the mean distribution network lengths per building connection are transferred from similar clusters.

Source: IFAM 2014

Table 80: Input data in economic viability calculation used to calculate district heating distribution costs

Input value	Unit	Value
Network losses	%	10

Specific distribution costs	€/m	700
Project costs	%	7 %
Time to final development of distribution network	a	5
Costs of BC line (includes 6 m BC line)	€/BC	4 000
Costs of BC line (> 6 m BC line)	€/m	350
Period of depreciation of lines	a	30
Costs of BC station (graduated by capacity)	€/BC	4 000 - 5 000
Time to final development of building connections	a	14
Period of depreciation of stations	a	20
Operational management + M lines	% of	1.00
Operational management + M BC stations	% of	5.00

Source: IFAM 2014

Table 81: Results of scenario CR 90 B

Town category	**Proportion of heat requirement in clusters suitable for cogeneration**					**Cogenera tion**
	> + 10 €/MWh	**> + 5 €/MWh**	**> 0 €/MWh**	**> - 5 €/MWh**	**> - 10 €/MWh**	**> 0 €/MWh**
I	27.6 %	43.4 %	**55.1 %**	65.7 %	78.5 %	**49.6 %**
II	18.8 %	28.4 %	**37.2 %**	56.5 %	73.9 %	**33.5 %**
III	17.7 %	23.2 %	**31.8 %**	39.4 %	52.7 %	**28.6 %**
IV	13.2 %	18.2 %	**30.7 %**	43.3 %	52.3 %	**27.6 %**
V	7.0 %	8.6 %	**15.2 %**	21.3 %	32.8 %	**13.7 %**
VI	9.1 %	15.0 %	**15.8 %**	18.6 %	28.5 %	**14.2 %**
VII	20.7 %	33.2 %	**52.6 %**	62.7 %	71.4 %	**47.3 %**
VIII	1.0 %	8.2 %	**35.6 %**	53.5 %	55.0 %	**32.1 %**
IX	3.6 %	3.6 %	**3.6 %**	5.9 %	16.4 %	**3.2 %**

Source: IFAM 2014

Table 82: Results of scenario CR 90 E

Town category	**Proportion of heat requirement in clusters suitable for cogeneration**					**Cogenera tion**
	> + 10 €/MWh	**> + 5 €/MWh**	**> 0 €/MWh**	**> - 5 €/MWh**	**> - 10 €/MWh**	**> 0 €/MWh**
I	50.9 %	57.1 %	**71.0 %**	86.9 %	94.7 %	**63.9 %**
II	30.5 %	45.0 %	**68.3 %**	77.5 %	82.2 %	**61.5 %**
III	24.7 %	35.7 %	**44.0 %**	62.6 %	68.9 %	**39.6 %**
IV	27.3 %	38.1 %	**46.4 %**	60.7 %	76.9 %	**41.7 %**
V	10.6 %	17.7 %	**27.2 %**	40.0 %	44.7 %	**24.5 %**
VI	15.0 %	16.5 %	**23.6 %**	34.2 %	45.6 %	**21.2 %**
VII	37.3 %	57.1 %	**66.6 %**	74.3 %	77.8 %	**59.9 %**
VIII	14.4 %	42.0 %	**54.7 %**	65.1 %	79.3 %	**49.3 %**

IX	1.3 %	5.2 %	**13.2 %**	19.4 %	21.3 %	**11.8 %**

Source: IFAM 2014

Table 83: Results of scenario CR 45 B

Town category	**Proportion of heat requirement in clusters suitable for cogeneration**					**Cogeneration**
	> + 10 €/MWh	**> + 5 €/MWh**	**> 0 €/MWh**	**> - 5 €/MWh**	**> - 10 €/MWh**	**> 0 €/MWh**
I	6.3 %	14.9 %	**29.4 %**	39.0 %	50.9 %	**13.2 %**
II	3.5 %	8.8 %	**18.1 %**	26.1 %	30.4 %	**8.1 %**
III	6.4 %	7.4 %	**18.4 %**	18.5 %	25.5 %	**8.3 %**
IV	3.8 %	4.8 %	**13.1 %**	16.6 %	29.0 %	**5.9 %**
V	3.4 %	4.8 %	**6.4 %**	8.4 %	10.4 %	**2.9 %**
VI	7.6 %	9.1 %	**9.1 %**	9.1 %	15.0 %	**4.1 %**
VII	4.4 %	10.0 %	**14.7 %**	26.3 %	32.6 %	**6.6 %**
VIII	1.0 %	1.0 %	**1.0 %**	5.5 %	21.9 %	**0.4 %**
IX	1.3 %	1.3 %	**1.3 %**	3.6 %	3.6 %	**0.6 %**

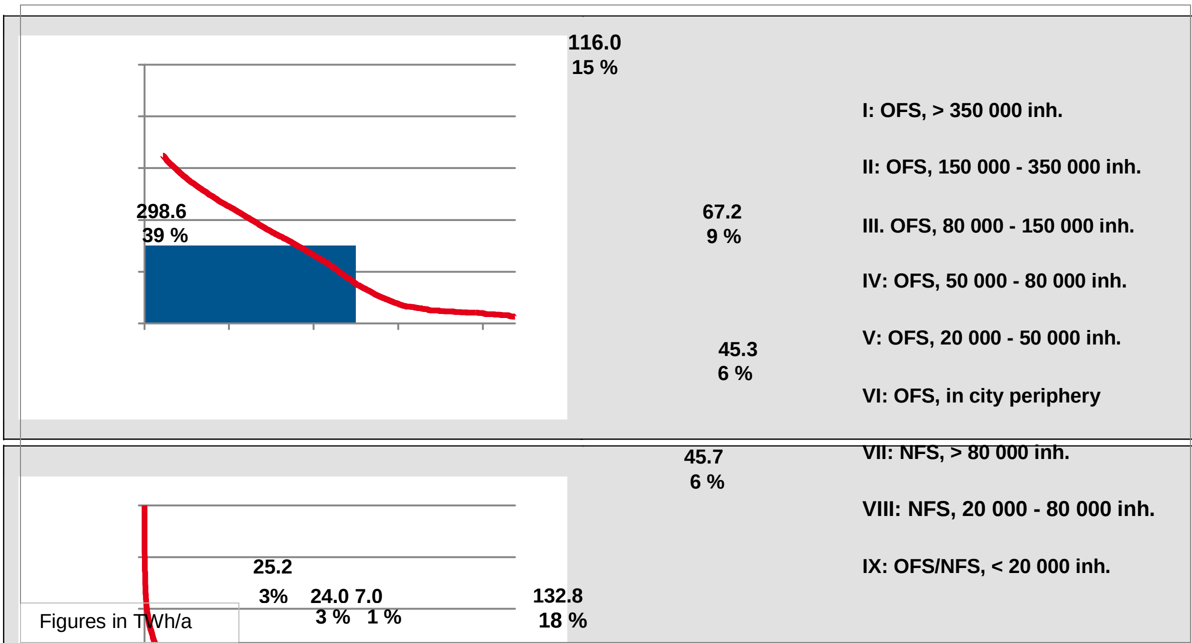
Source: IFAM 2014

Table 84: Results of scenario CR 45 E

Town category	**Proportion of heat requirement in clusters suitable for cogeneration**					**Cogeneration**
	> + 10 €/MWh	**> + 5 €/MWh**	**> 0 €/MWh**	**> - 5 €/MWh**	**> - 10 €/MWh**	**> 0 €/MWh**
I	22.0 %	37.8 %	**50.8 %**	55.0 %	60.6 %	**22.9 %**
II	13.6 %	19.9 %	**28.6 %**	34.6 %	50.3 %	**12.9 %**
III	13.6 %	18.5 %	**23.0 %**	30.2 %	37.4 %	**10.4 %**
IV	9.0 %	14.6 %	**22.2 %**	35.1 %	39.3 %	**10.0 %**
V	5.3 %	7.4 %	**8.6 %**	14.8 %	18.6 %	**3.9 %**
VI	9.1 %	9.1 %	**15.0 %**	15.0 %	16.5 %	**6.7 %**
VII	11.1 %	24.8 %	**31.1 %**	44.2 %	54.3 %	**14.0 %**
VIII	1.0 %	1.0 %	**10.4 %**	28.2 %	44.1 %	**4.7 %**
IX	1.3 %	1.3 %	**1.3 %**	3.6 %	5.2 %	**0.6 %**

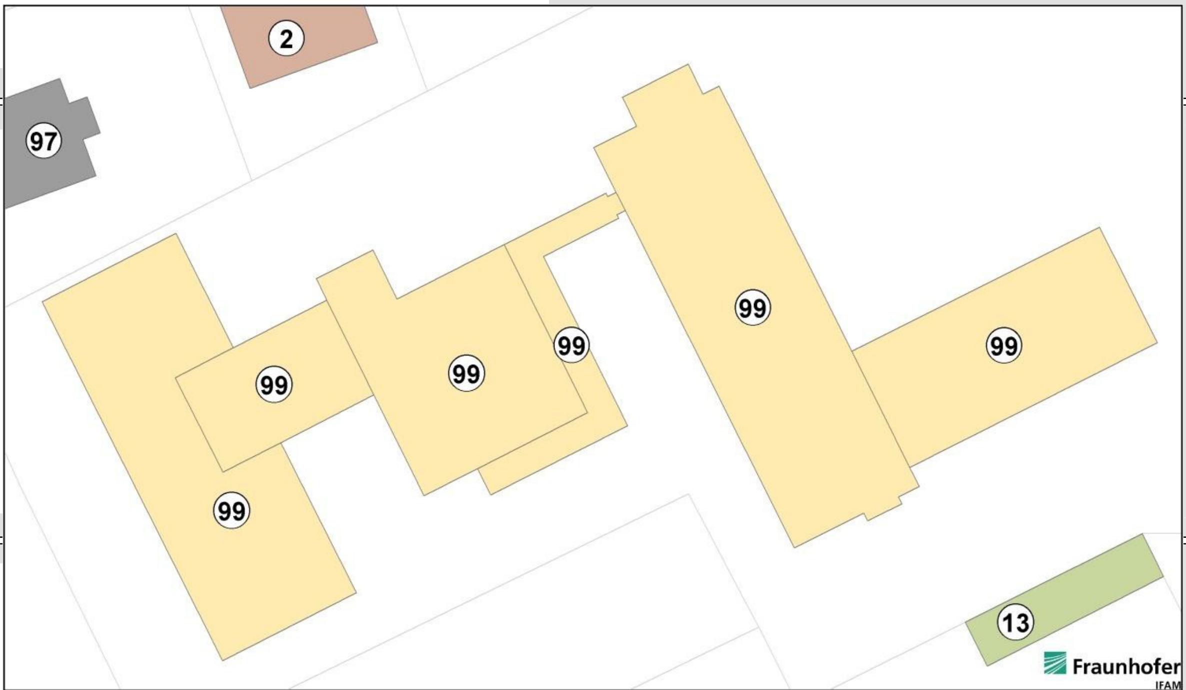
Source: IFAM 2014

Figure 72: Breakdown of useful heat requirement in the private household and CTS sectors in Germany by town categories



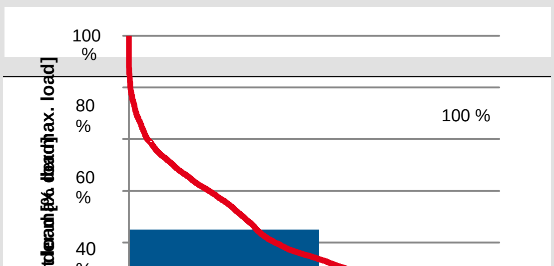
Source: IFAM 2014

Figure 73: Formation of shared addresses



Source: IFAM 2014

Figure 74: Building type profiles



Building type 1: One and two-family houses

- Full load hours of heating load: 1 878 h/a
- Full load hours of BHPP: 4 500 h/a
- Therm. cogeneration capacity: 25 % of peak load
- Ratio of cogeneration to annual heat: 60 %
- 50 %

80 %
60 %
40 %
20 %
0 %

0 2000 4 000 6 000 8 000
Hours in the year [h]

B
u
i

lding type 2: Apartment blocks

electricity use: 10 %

Quantity of heat at which a BHPP becomes economically viable

- economic not available
- business not available

- Full load hours of heating load: 2 331 h/a
- Full load hours of BHPP: 5 000 h/a
- Therm. cogeneration capacity: 30 % of peak load
- Ratio of cogeneration to annual heat: 64 %
- R
at
e
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e

100 %
80 %
60 %
40 %
20 %
0 %
Heat load [% der max. load]
0 2000 4 000 6 000 8 000
Hours in the year [h]

Building type 3: Education and research instit

utions

- Full load hours of heating load: 1 129 h/a
- Full load hours of BHPP: 4 000 h/a
- Therm. cogeneration capacity: 20 % of peak load
- Ratio of cogeneration to annual heat: 71 %
- Rate of private electricity use: 20 %

Quantity of heat at which a BHPP becomes economically viable

- economic 46 500 MWh/a
- business 6 500 MWh/a

100 %
80 %
60 %
40 %
20 %
0 %
Heat load [% der max. load]
0 2000 4 000 6 000 8 000
Hours in the year [h]

Bu ild

ing type 4: Healthcare facilities and residential homes

- Full load hours of heating load: 2 979 h/a
- Full load hours of BHPP: 6 000 h/a
- Therm. cogeneration capacity: 30 % of peak load
- Ratio of cogeneration to annual heat: 60 %
- Rate of private electricity use: 90 %

Quantity of heat at which a BHPP becomes economically viable

- economic 1 310 MWh/a
- business 210 MWh/a

100 % 80 % 60 %
der max. load]

40 %

20 %

0 %

0 2000 4 000 6 000 8 000

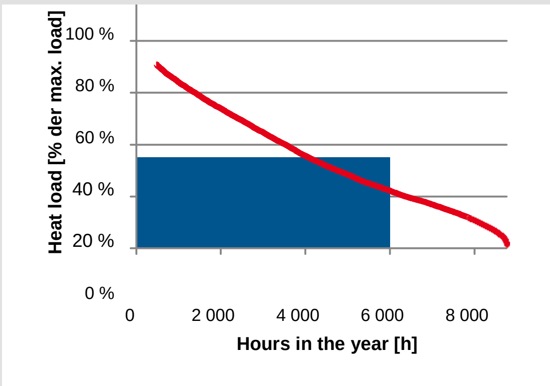
Hours in the year [h]

Building type 5: Office-type facilities

- Full load hours of heating load: 1 264 h/a
- Full load hours of BHPP: 4 000 h/a
- Therm. cogeneration capacity: 15 % of peak load
- Ratio of cogeneration to annual heat: 47 %
- Rate of private electricity use: 40 %

Quantity of heat at which a BHPP becomes economically viable

- economic 16 800 MWh/a
- business 2 500 MWh/a

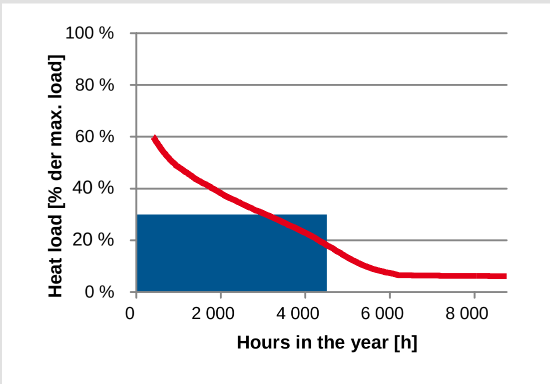


Building type 6: Indoor swimming pools

- Full load hours of heating load: 3 173 h/a
- Full load hours of BHPP: 6 000 h/a
- Therm. cogeneration capacity: 35 % of peak load
- Ratio of cogeneration to annual heat: 66 %
- Rate of private electricity use: 50 %

Quantity of heat at which a BHPP becomes economically viable

- economic 5 280 MWh/a
- business 850 MWh/a



Building type 7: Commerce

- Full load hours of heating load: 2 093 h/a
- Full load hours of BHPP: 4 500 h/a
- Therm. cogeneration capacity: 30 % of peak load
- Ratio of cogeneration to annual heat: 65 %
- Rate of private electricity use: 50 %

Quantity of heat at which a BHPP becomes economically viable

- economic 6 400 MWh/a
- business 1 100 MWh/a

Source: IFAM 2014

Table 85: Ratio of economically viable property cogeneration to possible quantity of heat with a district heating connection rate of 90 %

Town category	Business	Economic
I	7.7 %	2.7 %
II	5.3 %	2.2 %
III	7.8 %	1.2 %
IV	6.7 %	1.4 %
V	5.7 %	1.7 %
VI	6.7 %	1.1 %
VII	8.3 %	5.1 %
VIII	No information	No information
IX	4.6 %	0.0 %

Source: IFAM 2014

9.2.2 Potential of industrial cogeneration

Annex to Chapter 5.2 Potential of industrial cogeneration

First, the method used to determine cogeneration potential is explained (see Section 5.2). The results of the analyses are then divided into:

- heat requirement up to 300°C of the individual branches in 2012 which could theoretically be satisfied by cogenerated heat (see Section 5.2.2) and changes in coming decades (see Section 5.2.3);
- possible cogeneration potential in coming decades, with a distinction made between a possible reference change and an assumed policy-driven variation (see Section 5.2.4).

Annex to Chapter 5.2.1 Introductory explanations of the method and status of heat requirement and cogenerated heat production 2012

As the suitability of cogeneration in industry depends heavily on the heat requirement up to approx. 300°C (use of hot water, steam or thermo-oil), which varies considerably from one branch of industry to another, first the heat requirement up to 300°C must be compiled for individual branches of industry. For that, the corresponding sources and our own surveys and estimates were used to make that differentiation first for the year 2012 (see Table 27).

The next step was to determine how much of that heat requirement as fuel requirement (in some exceptions this is also the electricity requirement, e.g. injection moulding) was already produced by cogenerated heat in the individual branches in 2012 and thus is not available as further potential. For that we compared the ratio of heat < 300°C to quantities of fuel according to the energy balance (See AEGB, detailed table for 2012) and compared it with information on cogenerated heat production in DESTATIS 2013 and 2014 (see Table 28.

The result illustrates the anticipated high ratio of cogenerated heat to fuel requirement up to 300°C in

- raw chemicals: 109 % (part of the heat generated by CHPP is delivered to neighbouring undertakings in other branches);
- the cellulose and paper industry: 63 % and
- the food industry: 37 %, due mainly to use of cogeneration in the sugar industry.

Overall, approx. 40 % of the heat requirement < 300°C in industry was supplied by cogenerated heat. It is not possible to give an exact figure, as statistics are not complied on BHPP under 1 MW and there is no way of establishing how many of the approx. 55.000 small BHPP served what proportion of the industrial heat requirement back in 2012.

The industry average ratio of cogenerated electricity to the overall electricity requirement (11 %) is understandably relatively small. As expected, the highest percentages are in the raw chemicals and paper industry (approx. 30 %).

This provisional result for 2012 alone illustrates that even the technical potential for cogeneration could at best be double the use of cogeneration, if not less, as the industrial heat requirement < 300°C might decline in future if there are major efficiency improvements and slow growth in industry, especially as there is still considerable potential to use waste heat in numerous cases to satisfy the low-temperature heat requirement (e.g. waste heat from compressors or drying plants).

As explained previously in Section 4.3.4, heat-operated absorption refrigeration production may increase the capacity utilisation of a CHPP and thus the rate of return on the overall operation of the plant in question. This applies in particular where waste gas containing hydrocarbons from necessary post-combustion are concentrated and channelled to a CHPP. The additional heat generated can then be used to generate refrigeration using cheap absorption technology. Such applications are seen in the chemical industry and the consumer goods industry (see also Table 86 with cooling requirement by temperature ranges) and also illustrate that rate-of-return calculations are sometimes simplifying example calculations.

The foodstuffs industry, the chemical industry incl. the pharmaceutical industry, plastics processing and other branches of industry have very high refrigeration requirements between -15°C and +15°C. Clean room technology, which is also moving into the investment goods industry due to its high quality standards, is expected to increase the demand for refrigeration for air-conditioning.

Overall, industrial refrigeration -15°C and +15°C currently (2012) has a power requirement of approx. 10 900 GWh/a, part of which could be substituted by trigeration or waste heat. The current power requirement corresponds in arithmetic terms to approx. 6 % of the industrial heat requirement < 300°C. This percentage suggests that industrial refrigeration tends to improve the rate of return rather than act as a separate driving force for cogeneration.

Table 86: Distribution of refrigeration requirement in 2012 by branch of industry and different temperature levels

Industrial sectors	Distribution of refrigeration requirement by		
	< -15 °C	- 15 - 0 °C	0 - 15 °C

Food and tobacco	56.0 %	14.0 %	30.0 %
Automobile manufacture	0.0 %	0.0 %	100.0 %
Quarrying of stone and soil, other mining	0.0 %	0.0 %	100.0 %
Glass and ceramics	0.0 %	0.0 %	100.0 %
Raw chemicals	38.0 %	12.0 %	50.0 %
Rubber and plastic products	0.0 %	0.0 %	100.0 %
Machine engineering	2.5 %	2.5 %	95.0 %
Metal processing	0.0 %	0.0 %	100.0 %
Metal production	0.0 %	0.0 %	100.0 %
Non-ferrous metals/foundries	0.0 %	0.0 %	100.0 %
Paper industry	0.0 %	0.0 %	100.0 %
Other chemical industry	45.5 %	4.5 %	50.0 %
Rest of the economy	4.5 %	0.5 %	95.0 %
Processing of stone and soil	0.0 %	0.0 %	100.0 %

Source: IREES 2014

Projected heat requirement of industry

Changes to the use of cogeneration in future depend not least on changing heat requirements in coming decades. Therefore, the next step is to project the heat requirement < 300°C, whereby both efficiency gains and structure developments in industry, as well as technological changes could noticeably alter the heat requirement < 300°C.

First, changes in the gross added value of industry and its branches from 2012 to 2050 were adopted from a previous Prognos projection of economic development in Germany (2014). There has been a marked interindustrial structural change towards less energy-intensive branches of industry (investment goods and consumer goods industries), which increase at an above-average rate in both projection periods (see Table 29).

Furthermore, for very energy-intensive branches, we were able to use changes to physical production of important raw materials (e.g. oxygen and electric steel, primary and secondary aluminium, cement, paper etc.). These changes in production were multiplied by projected fuel and electricity intensities. Aside from foreseeable energy efficiency gains in industry, account is also taken of intrasectoral structural effects on less energy-intensive production structures due to higher standards, product support services in the investment and consumer goods industry and other additional added value effects.

In the past, the demand elasticity of power (ratio between growth in energy requirement and growth rate of gross added value) was nearly always lower with the demand elasticity of fuel. That was due in the past to progressive mechanisation and automation of industrial production and other developments, such as growth in clean room technology etc. We assumed that the mechanisation process would slowly reach saturation point in the future and that the elasticity of demand for power would converge with the elasticity of demand for fuel (see Table 87).

Moreover, account had to be taken for each branch of the extent to which, aside from energy efficiency options, intra-industrial structural effects (mostly on less energy-intensive sub-branches, e.g. due to stagnation of cement or sugar production, in the stone and soil industry of the food industry) impact on energy intensities.

Finally, we had to check in each individual branch if converting production processes caused specific changes to the fuel requirement or electricity requirement (e.g. by converting production technology from a wet to a dry process, which eliminates the heat requirement for washing and compressed air and thus doubles the electricity requirement of the factory in question).

The most important effects on individual branches are reported below, in order to explain the projected change in fuel and heat requirements.

- In the *food and luxury food industry*, breweries stagnate and production declines in energy-intensive sugar production (due to the end of the EU sugar regulation in 2017). Ready meals with cold chains increase further. These intra-industrial structural changes reduce the specific energy requirement in addition to the efficiency gains.
- In *automobile manufacture*, although gross added value increases disproportionately, the number of vehicles manufactured stops increasing. This is again compounded by efficiency gains.
- In *glassware, ceramics and bricks*, production of hollow glass and consumer ceramics declines slightly, whereas production of more added value-intensive plate glass (triple glazing, PV modules) and special glass and ceramics and glass fibre continues to increase slightly. Aside from structural effects, additional efficiency potential is also realised. Overall, the added value of the sector remains constant.

Table 87: Power and fuel intensity 2012-2050, subdivided by industrial sector

Industrial sectors	Energy source	Specific parameter per gross added value (kWh / € GAV)					Annual rate of change	
		2012	2020	2030	2040	2050	2012-2030	2012-2050
Food and tobacco	Electricity	0.58	0.57	0.56	0.54	0.52	-0.2 %	-0.2 %
	Fuels	1.28	1.23	1.15	1.08	1.01	-0.6 %	-0.4 %
Automobile manufacture	Electricity	0.21	0.20	0.20	0.19	0.18	-0.3 %	-0.3 %
	Fuels	0.20	0.19	0.17	0.16	0.15	-0.6 %	-0.5 %
Quarrying of stone and soil, other mining	Electricity	1.14	1.12	1.08	1.03	0.97	-0.3 %	-0.3 %
	Fuels	1.41	1.35	1.27	1.20	1.12	-0.5 %	-0.4 %
Glass and ceramics	Electricity	0.89	0.86	0.82	0.77	0.72	-0.5 %	-0.4 %
	Fuels	3.27	3.13	2.96	2.79	2.59	-0.5 %	-0.4 %
Raw chemicals	Electricity	2.38	2.35	2.28	2.19	2.08	-0.2 %	-0.2 %
	Fuels	4.97	4.89	4.75	4.56	4.32	-0.3 %	-0.2 %
Rubber and plastic products	Electricity	0.23	0.22	0.21	0.20	0.19	-0.4 %	-0.3 %
	Fuels	0.84	0.81	0.77	0.72	0.66	-0.5 %	-0.4 %
Machine engineering	Electricity	0.18	0.17	0.16	0.16	0.15	-0.4 %	-0.3 %
	Fuels	0.17	0.16	0.15	0.14	0.13	-0.7 %	-0.5 %
Metal processing	Electricity	4.81	4.66	4.46	4.24	3.99	-0.4 %	-0.3 %
	Fuels	4.89	4.69	4.42	4.08	3.69	-0.6 %	-0.5 %
Metal production	Electricity	2.60	2.54	2.47	2.37	2.25	-0.3 %	-0.2 %
	Fuels	16.73	16.46	16.05	15.58	15.04	-0.2 %	-0.2 %
Non-ferrous metals/foundries	Electricity	1.80	1.77	1.72	1.63	1.52	-0.3 %	-0.3 %
	Fuels	1.63	1.61	1.55	1.46	1.32	-0.3 %	-0.3 %
Paper industry	Electricity	2.11	2.07	2.02	1.96	1.88	-0.2 %	-0.2 %
	Fuels	4.33	4.23	4.08	3.92	3.73	-0.3 %	-0.3 %
Other chemical industry	Electricity	0.24	0.23	0.21	0.19	0.17	-0.7 %	-0.5 %
	Fuels	0.62	0.59	0.54	0.49	0.44	-0.8 %	-0.6 %
Rest of the economy	Electricity	0.18	0.17	0.16	0.15	0.13	-0.6 %	-0.5 %
	Fuels	0.21	0.19	0.18	0.16	0.15	-0.8 %	-0.6 %
Processing of stone and soil	Electricity	1.22	1.19	1.16	1.12	1.07	-0.3 %	-0.2 %
	Fuels	7.62	7.44	7.19	6.87	6.50	-0.3 %	-0.3 %
Industry overall	**Electricity**	**0.50**	**0.46**	**0.42**	**0.38**	**0.35**	**-0.9 %**	**-0.7 %**
	Fuels	**1.15**	**1.03**	**0.91**	**0.81**	**0.72**	**-1.3 %**	**-0.9 %**

Source: IREES 2014

- In the *raw chemicals* industry, energy-intensive electrolysis (e.g. of chlorine and fluorine) declines by volume and production of plastic precursors stagnates; this is also reflected in stagnating gross added value from 2025, which only increases by 10 % from 2012 to 2025. Further slight efficiency gains are also realised.

- For *rubber and plastic products*, processing of plastics drives growth, whereas production of rubber products stagnates. In plastics processing, considerable efficiency gains are realised (especially in injection moulding: up to 50 %).
- In *machine engineering and metal processing* there is a marked increase in product support services and in the trend towards higher added value per machine and plant. From a technological perspective, it should be noted that automation continues to progress and clean room technology and dry manufacture spread. This covers efficiency gains on the power side, which become even more marked in terms of fuels (high efficiency potential, e.g. in powder coating, use of waste heat for warm baths).
- *Metal production* is very complex due to the primary and secondary routes for steel, aluminium and copper and thus changes to specific power and fuel requirements for these aggregated branches can only be plausibly understood based on our own model and a series of assumptions on physical production. Thus we assume that steel production will fall to 40 million t by 2020 and to 33 million t by 2050, with the ratio of electric steel rising continuously to 40 % in 2050. We assume that production of primary aluminium will fall by 20 % by 2050 and that secondary production will rise by 25 % compared to 2012.
- These structural changes result in a sharp decline in fuel and power, whereas the slight increase in gross added value of this sector will basically be achieved through higher grade steel and non-ferrous alloys. Energy efficiency gains tend to be small in this sector. However, the potential to use waste heat has not yet been taken into account.
- *Processing of non-ferrous metals and non-ferrous foundries* also moves towards higher-grade products (through to expanded metal products), whereas physical production only increases slightly. These structural effects are compounded by efficiency gains.
- While the gross added value of *paper and cardboard production* continues to increase slightly, production falls by a good 10 % by 2050 (conservative estimate). These structural effects are compounded by efficiency gains.
- The very dynamic *other chemicals*, especially pharmaceuticals and special chemicals, increase their gross added value on average twice as fast as the industry average. Value added effects are assumed to be especially high here. Moreover, there is considerable energy efficiency potential.

- In the *rest of industry* (mostly consumer good branches), the trend is likewise towards higher added value which is again compounded by existing efficiency potential.
- Although the *stone and soil industry* increases in terms of added value by a further 20 % by 2050; however, that is basically driven by product-support services (e.g. ready-mix concrete) or special products. We assume that energy-intensive cement production will decline in terms of volume. This is compounded by efficiency gains.

For industry as a whole, the annual changes in energy intensities peak at -0.9 %/a (electricity) and 1.3 %/a (fuel) in 2030. That is because, aside from the aforementioned efficiency and structural changes, they also reflect inter-industrial structural changes, i.e. stagnation in the energy-intensive raw materials industry and disproportionately high growth in the investment and consumer goods industry. Inter-industrial structural changes slow down after 2030 (see Table 87).

The change in gross added value is multiplied by the energy intensity to give the change in electricity and fuel requirement from 2012 to 2050 (see Section 5.2.3).

Annex to 5.2.2 Fuel and power consumption by branch and size of undertaking, 2012

The electricity and fuel consumptions by individual branches of industry given in Table 28 were subdivided by three sizes of undertakings based on DESTATIS cost structure statistics (2013) (see Table 30). This subdivision was essential in order to classify the frequency of various CHPP capacities. Undertaking were classed based on a combination of energy intensity and number of employees rather than based on a standard employment class in the cost structure statistics. In energy-intensive branches, the employment class was reduced by one category (e.g. for small undertakings from 100 to 50 employees, as the usable capacity and type of CHPP depends primarily on the undertaking's annual energy consumption).

As expected, the power and fuel requirements of the individual branches of industry vary enormously:

- In the raw materials industry and automobile industry, the large undertakings account for a large proportion of final energy consumption by the branch of industry in question – mostly over three-quarters of the final energy requirement of the branch of industry concerned (see Table 30).
- In the rest of industry, small and medium-sized undertakings account for a much higher proportion of final energy consumption by the branch of industry in question (e.g. small stone and soil quarrying companies: 51 % and metal processing: 30 %).

This result alone (combined with the figures in Table 28) illustrates that the future potential of cogeneration should tend to lie in investment and consumer goods industries and, in those industries, in smaller and medium-sized undertakings.
This means that medium-sized and larger BHPP and smaller gas turbines plants will tend to be used (see Section 4.3.3).

Across the industry, 66 % of final energy (476 TWh) was allocated to large undertakings, 25 % (182 TWh) was allocated to medium-sized undertakings and the remaining 8.5 % (61 TWh) of final energy consumption was allocated to small undertakings.

Annex to 5.2.3: Heat (< 300 °C) and cooling requirements in industry up to 2020 and prospects up to 2030 and 2050

The gross added values of the individual branches of industry given in Table 29 are multiplied by the energy intensities in Table 87 to give the fuel and power requirements of industry. The ratio of the heat requirement < 300°C to fuel consumption in 2012 was kept constant as a rule, in order to project the change in the heat requirement < 300°C between 2012 and 2050 (see Table 31).

The results give a differentiated picture for the individual branches:

- The heat requirement of industry as a whole < 300°C continues to rise from 2012 to 2030 by 0.9 % per annum. After 2035 it falls by approx. 1.5 % per annum so that the average increase for the period from 2012 to 2050 is just 0.3 % per annum. Demand elasticity therefore falls from 0.69 in the first period to below zero in the second period.
- Disproportionate increases in the heat requirement < 300°C are expected in other chemicals, especially pharmaceutical and fine chemicals (2.2 % and 1.3 % per annum) and in automobile manufacture and machine engineering and the foodstuffs industry (1.1 % and 0.4 % per annum).
- In some branches of industry, including stone and soil quarrying, the heat requirement < 300°C falls from now on. The heat requirement in this temperature range in the glass and ceramics industry and in metal processing and metal production and the paper industry falls from 2020 onwards and the heat requirement of the raw chemicals industry and the
‘rest of industry’ falls from 2030 onwards.

This result means that in branches whose heat requirement < 300°C is stagnating or forecast to fall and which already have a high proportion of cogeneration (e.g. raw chemicals and paper), only re-investment in CHPP can be expected. Potential for large-scale development of cogeneration is expected mainly in those branches of industry in which the heat requirement < 300°C is high and rising and only a small proportion of cogeneration has been achieved to date (see Table 31 and Table 28 and Section 5.2.4).

Qualitatively speaking, we can therefore conclude even at this stage that foodstuffs, rubber and plastics and other chemicals have the highest cogeneration potential, each with possibly around 10 TWh (approx. 35 PJ) per annum. All three of these large branches also have an increasing refrigeration requirements of between 6.5 and 0.8 TWh (23 to 2.9 PJ) per annum (see Table 32).

The refrigeration requirement of the individual branches of industry were determined, like their heat requirements, based on changes in gross added value and cooling intensity (ratio of the energy requirement for cooling to gross added value). A series of specific technological changes was assumed here:

- In the foodstuffs industry, the refrigeration requirement is increasing disproportionately compared to gross added value due to the increasing proportion of ready meals.
- The same applies to automobile manufacture and machine engineering and the rest of the chemical industry (especially pharmaceuticals), where clean room technology is used.

Overall, the cooling requirement of industry is disproportionately low compared to the increase in gross added value, as the considerable cooling requirement of the raw chemicals industry declines over the projection period. This includes low-temperature cooling (e.g. for nitrogen and oxygen extraction).

9.3 Additional information on Chapter 6 Potential role of cogeneration in the future power and heat system

Table 88: Contribution margin 1 of public CHPP without cogeneration surcharge

Contribution margin 1 in EUR2013/kW
Total revenue from sales of power and heat, network user fees and cogeneration surcharge saved, minus CO_2, fuel and variable costs

Plant:	BHPP 6	G&S 1	G&S 2	G&S 3	G&S 4	Coal 1	Coal 2
2008	94	50	103	130	155	178	233
2009	44	30	52	63	75	70	104
2010	36	20	45	63	81	99	143
2011	30	11	38	57	77	66	121
2012	11	6	11	16	20	66	112
2013	5	2	2	3	4	55	95
2014	4	2	1	1	1	62	101
2015	4	2	1	1	0	40	79
2016	4	2	1	0	0	29	65

2017	5	2	2	1	0	13	41
2018	5	2	2	2	1	0	25
2019	5	2	2	1	0	-2	25
2020	4	2	1	0	0	7	37
2021	4	2	1	0	0	4	37
2022	5	2	2	2	2	2	36
2023	6	3	3	2	3	3	34
2024	7	3	4	4	6	4	34
2025	9	5	7	8	11	8	37
2026	11	6	9	12	15	10	41
2027	13	8	12	16	19	12	42
2028	19	12	18	22	27	17	44
2029	18	11	17	22	27	15	44
2030	23	14	22	28	34	19	48
2031	26	17	26	32	39	21	48
2032	26	16	26	33	40	20	47
2033	30	20	30	37	45	25	48
2034	37	25	36	44	52	31	53
2035	46	34	46	53	61	39	60

Source: Prognos 2014

Table 89: Contribution margin 1 of public CHPP with cogeneration surcharge

Contribution margin 1 in EUR2013/kW
Total revenue from sales of power and heat, network user fees and cogeneration surcharge saved, minus CO_2, fuel and variable costs

Plant:	BHPP 6	G&S 1	G&S 2	G&S 3	G&S 4	Coal 1	Coal 2
2008	109	62	120	149	177		260
2009	80	57	90	106	121		154
2010	75	46	86	108	130		195
2011	66	34	76	100	124		171
2012	43	25	47	58	68		185
2013	20	10	21	26	31		166
2014	13	6	13	18	22		172
2015	14	6	13	18	22		149
2016	12	5	12	16	20		133
2017	8	3	7	10	13		106
2018	7	2	5	6	9		84
2019	8	3	6	8	12		79
2020	10	4	9	14	19		37
2021	9	3	8	13	18		37
2022	10	4	9	14	20		36
2023	12	4	11	16	21		34
2024	14	5	13	19	25		34
2025	18	8	18	24	32		37
2026	22	10	22	29	36		41
2027	25	12	25	33	41		42
2028	32	17	32	41	27		44
2029	32	16	32	42	27		44
2030	37	20	37	48	34		48
2031	40	22	41	32	39		48
2032	40	22	41	33	40		47
2033	44	25	44	37	45		48
2034	50	31	50	44	52		53
2035	58	40	59	53	61		60

Source: Prognos 2014

Table 90: Contribution margin 2 of public CHPP without cogeneration surcharge

Contribution margin 1 in EUR2013/kW
Total revenue from sales of power and heat, network user fees and cogeneration surcharge saved, minus CO_2, fuel and variable costs

Plant:	BHPP 6	G&S 1	G&S 2	G&S 3	G&S 4	Coal 1	Coal 2
2008	109	62	120	149	177	178	260
2009	80	57	90	106	121	70	154
2010	75	46	86	108	130	99	195
2011	66	34	76	100	124	66	171
2012	43	25	47	58	68	66	185
2013	20	10	21	26	31	55	166
2014	13	6	13	18	22	62	172
2015	14	6	13	18	22	40	149
2016	12	5	12	16	20	29	133
2017	8	3	7	10	13	13	106
2018	7	2	5	6	9	0	84
2019	8	3	6	8	12	-2	79
2020	10	4	9	14	19	7	37
2021	9	3	8	13	18	4	37
2022	10	4	9	14	20	2	36
2023	12	4	11	16	21	3	34
2024	14	5	13	19	25	4	34
2025	18	8	18	24	32	8	37
2026	22	10	22	29	36	10	41
2027	25	12	25	33	41	12	42
2028	32	17	32	41	27	17	44
2029	32	16	32	42	27	15	44
2030	37	20	37	48	34	19	48
2031	40	22	41	32	39	21	48
2032	40	22	41	33	40	20	47
2033	44	25	44	37	45	25	48
2034	50	31	50	44	52	31	53
2035	58	40	59	53	61	39	60

Source: Prognos 2014

Table 91: Contribution margin 2 of public CHPP with cogeneration surcharge

Contribution margin 2 in EUR2013/kW
Contribution margin 1 minus fixed operating costs

Plant:	BHPP 6	G&S 1	G&S 2	G&S 3	G&S 4	Coal 1	Coal 2
2008	93	42	104	133	161		238
2009	64	37	74	90	105		132
2010	59	26	70	92	114		173
2011	50	14	60	84	108		149
2012	27	5	31	42	52		163
2013	4	-10	5	10	15		144
2014	-3	-14	-3	2	6		150
2015	-2	-14	-3	2	6		127
2016	-4	-15	-4	0	4		111
2017	-8	-17	-9	-6	-3		84
2018	-9	-18	-11	-10	-7		62
2019	-8	-17	-10	-8	-4		57
2020	-6	-16	-7	-2	3		15
2021	-7	-17	-8	-3	2		15
2022	-6	-16	-7	-2	4		14
2023	-4	-16	-5	0	5		12

2024	-2	-15	-3	3	9		12
2025	2	-12	2	8	16		15
2026	6	-10	6	13	20		19
2027	9	-8	9	17	25		20
2028	16	-3	16	25	11		22
2029	16	-4	16	26	11		22
2030	21	0	21	32	18		26
2031	24	2	25	16	23		26
2032	24	2	25	17	24		25
2033	28	5	28	21	29		26
2034	34	11	34	28	36		31
2035	42	20	43	37	45		38

Source: Prognos 2014

Table 92: Economic operating hours of public CHPP without cogeneration surcharge

Hours with economic operation
Number of hours with positive contribution margin

h/a	BHPP 6	G&S 1	G&S 2	G&S 3	G&S 4	Coal 1	Coal 2
2008	2 876	1 553	3 178	3 955	4 697	5 529	6 750
2009	1 803	1 195	2 268	2 948	3 697	3 997	5 772
2010	1 757	931	2 395	3 478	4 604	5 775	7 179
2011	2 035	742	2 629	3 696	4 804	4 869	6 941
2012	674	323	975	1 511	2 232	5 599	7 407
2013	307	123	524	854	1 199	5 772	7 598
2014	121	24	236	485	758	6 157	7 788
2015	118	19	251	490	783	5 492	7 163
2016	80	19	215	449	708	4 996	6 630
2017	3	1	45	116	238	4 100	5 867
2018	0	0	7	30	79	3 285	5 117
2019	9	0	34	102	209	3 011	4 888
2020	76	7	146	341	611	3 124	4 906
2021	69	8	136	316	591	3 034	4 946
2022	118	30	189	379	670	2 696	5 017
2023	141	47	212	408	669	2 290	5 153
2024	230	80	329	571	876	2 086	5 059
2025	353	133	463	747	1 086	1 943	4 951
2026	447	171	582	893	1 324	1 881	4 724
2027	547	205	681	1 062	1 565	1 841	4 507
2028	650	272	794	1 187	1 679	1 774	4 072
2029	708	273	884	1 346	2 009	1 807	4 177
2030	801	331	990	1 477	2 223	1 794	4 024
2031	828	382	992	1 508	2 243	1 697	3 705
2032	862	358	1 050	1 584	2 366	1 661	3 677
2033	910	391	1 079	1 615	2 376	1 484	3 440
2034	900	407	1 071	1 602	2 361	1 309	3 106
2035	896	449	1 050	1 579	2 299	1 169	2 801

Source: Prognos 2014

Table 93: Economic operating hours of public CHPP with cogeneration surcharge

Hours with economic operation
Number of hours with positive contribution margin

h/a	BHPP 6	G&S 1	G&S 2	G&S 3	G&S 4	Coal 1	Coal 2
2008	3 231	1 849	3 556	4 435	5 261		7 146
2009	2 981	2 005	3 398	4 133	4 882		6 589
2010	3 176	1 844	3 708	4 786	5 778		7 659

2011	3 309	1 704	3 823	4 931	5 972	7 516
2012	2 189	1 272	2 480	3 108	3 952	7 709
2013	1 484	824	1 665	2 047	2 530	7 822
2014	1 105	528	1 289	1 653	1 978	7 896
2015	1 175	568	1 362	1 718	2 091	7 651
2016	1 102	545	1 318	1 694	2 038	7 345
2017	758	384	925	1 280	1 619	6 952
2018	551	247	700	999	1 335	6 562
2019	670	276	802	1 149	1 522	6 333
2020	912	408	1 072	1 496	1 921	4 906
2021	859	333	1 011	1 446	1 869	4 946
2022	902	332	1 047	1 505	1 970	5 017
2023	904	324	1 060	1 532	2 046	5 153
2024	1 010	361	1 165	1 634	2 162	5 059
2025	1 116	443	1 280	1 746	2 312	4 951
2026	1 218	500	1 365	1 848	2 497	4 724
2027	1 310	560	1 462	1 934	2 622	4 507
2028	1 391	602	1 538	2 027	1 679	4 072
2029	1 476	644	1 617	2 176	2 009	4 177
2030	1 567	688	1 711	2 285	2 223	4 024
2031	1 560	720	1 706	1 508	2 243	3 705
2032	1 582	693	1 715	1 584	2 366	3 677
2033	1 571	705	1 714	1 615	2 376	3 440
2034	1 534	692	1 671	1 602	2 361	3 106
2035	1 483	699	1 612	1 579	2 299	2 801

Source: Prognos 2014