Assessment of the potential for application of high-efficiency cogeneration and efficient district heating and cooling

Final report

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Summary

This report presents results of a study conducted to assess the potential for efficient district heating and high-efficient cogeneration of heat and power (CHP) in Austria. The study was conducted on behalf of the Austrian Federal Ministry of Science and Economics and aims at supporting the authorities to fulfil the reporting duties related to the Energy Efficiency Directive 2012/27/EU, Article 14. This article asks for a comprehensive assessment of technical and economic potentials of CHP and district heating on a geographically disaggregated level until the year of 2025 from each member state.

The main results of the study comprise this report and an **interactive heat map for Austria** (see http://www.austrian-heatmap.gv.at) including the following content:

- Geographically disaggregated heat densities for space heating and domestic hot water in Austria
- Heat demand of the most relevant industrial sites
- Technical potentials for district heating, CHP, waste heat, geothermal heat, solar thermal and district cooling
- Economic potentials of the technologies mentioned above for regions with high technical district heating potential
- Locations of existing district heating grids and heat supply technologies in Austria

In the following the major results are presented:

Model results suggest that final energy demand for **space and water heating** in Austria will decline starting from below 100 TWh_{th} in the base year of 2012 to 78 TWh_{th} in year 2025 in a current policy scenario or to around 65 TWh_{th} in an ambitious energy efficiency scenario.

For both, district heating and heat from CHP plants, a **maximum technical potential** (district heating in regions with heat densities >10 GWh/km^2 and high connection rates of 90% within those regions) and a **reduced technical potential** (heat densities >20 GWh/km^2 and connection rates of 45%) was calculated based on regionalized data on heat demand. For district heating a maximum potential of 63 TWh_{th} for the base scenario in 2025 was estimated. The reduced technical potential amounts to 22 TWh_{th}. The maximum potential for CHP heat is around 57 TWh_{th} while the reduced potential declines to 20 TWh_{th}. The resulting electricity generation from CHP is estimated to be 49 TWh_{el} and 19 TWh_{el} respectively for the exploitation of the reduced potential. It should be noted that if the maximum technical potential was to be deployed, the electricity production from CHP plants is expected to exceed the residual demand for electricity in Austria significantly. The production from an exploitation of the reduced CHP potential can be almost fully integrated in the electricity system.

Using the calculated technical potentials, a **cost benefit analyses** was conducted to estimate the economic potential for district heating and CHP for various scenarios. Assuming an interest rate of 4% and depreciating the capital costs over the full technical lifetime of all technologies the economic potential is to be seen as social planner perspective rather than an economic assessment of incentives for private investors. Furthermore the **economic potential of district heating** highly depends on the assumed connection rates. With connection rates of 90% the potential is estimated to be as high as 52 TWh_{th} because heating grids seem to be economically feasible even for relatively low heat densities. However if a connection rate of only 45% is assumed the economic potential goes down to 20 TWh_{th}. **Economic potentials of CHPs** in district heating are very low for the baseline scenarios because of low electricity prices. It is estimated that in the year 2025 6 TWh of heat will be provided by existing CHP plants. Only in the scenarios with low gas prices or high CO_2 prices an additional potential of 13 and 20 TWh_{th} respectively is calculated.

Potential for **CHP** heat and **waste heat** were also assessed for the **industry sector**. Assuming that CHP can supply process heat of up to 500°C the technical potential heat from industrial CHPs is around 35 TWh_{th}, while the resulting electricity production is around 12 TWh_{el}. Waste heat potentials were calculated for temperature levels of >100°C and <100°C (in combination with heat pump or just for low temperature heating grids). The technical potential for waste heat >100°C is estimated to almost 3

TWh$_{th}$, while the potential below 100°C is 8.5 TWh$_{th}$. It should be noted that those potentials are largely based on extrapolations from other studies on industrial processes. The assessment of the economic feasibility has to be made for each process and must consider the characteristics of process heat demand and its supply at each site individually which was out of scope of this study.

Furthermore, potentials for **renewable energy carriers** were calculated mainly based on results from literature. The technical potential for heat from biomass in Austria was assumed to be 31 TWh (without imports). The technical potential for heat from solar thermal systems was estimated to be 37.5 TWh in total. Out of this, 14.5 TWh could be produced on rooftops classified as big enough for feed in into district heating networks. However it is assumed that a significant amount of heat storage capacity is needed to integrate this potential and the cost benefit analyses shows that the existing potential is not competitive compared to other options under current market conditions. The potential for deep geothermal heat is limited to almost 1.9 TWh and potential sites are only available in selected regions. The use of ambient heat through heat pumps however could possibly cover a significant part of the heating demand especially in rural areas. Also the potential of large scale heat pumps in district heating grids is supposed to be high. However, there are still great uncertainties concerning heat sources and related costs in urban regions which is why the potential could not be quantified in this study.

Model results estimate the building related energy **demand for cooling** in the year 2025 to be 2.6 TWh$_{th}$ in Austria. The technical potential for absorption chillers which are only supposed to be relevant for buildings with high cooling needs and high full load hours is estimated to be slightly over 0.3 TWh$_{th}$.

In addition to quantifying technical and economic potentials the study also discusses barriers related to the realization of existing potentials which also can be found in this report.

Due to the geographical scope of the study related to the reporting duties of the Energy Efficiency Directive some of the results are based on aggregated assumptions, literature values and extrapolations. Therefore it should be noted that although the potentials where quantified on a regionally disaggregated level more detailed studies will have to be conducted to assess the economic feasibility of each individual district heating project (e.g. distribution costs, local biomass potential, etc.). All results and the visualization of the Austrian heating demand and relevant supply technologies can be found here: http://www.austrian-heatmap.gv.at

Contents

1 Introduction and objectives

This project, which is entitled 'Comprehensive assessment of the potential for use of high-efficiency cogeneration and efficient district heating and cooling', pursues the following objectives:

- to determine the potential for application of high-efficiency cogeneration, including high-efficiency micro-cogeneration;
- to determine the potential for application of efficient district heating and cooling;
- to support the contracting party in relation to the aforementioned points as regards their reporting obligations under Article 14 and Annexes VIII and IX of Directive 2012/27/EU (Energy Efficiency Directive).

The work is based on the following documents, including the objectives and methods set out therein:

- tender specification
- Article 14 and Annexes VIII and IX of Directive 2012/27/EU (Energy Efficiency Directive)
- Interpretative Note of the European Commission on this article (this project takes account of the most recent revised version of the document).

The tender requirements have been fully complied with, i.e. the outcomes of the project as stipulated by the tender are:

1. potential for use of high-efficiency cogeneration, including high-efficiency micro-cogeneration;
2. potential for use of efficient district heating and cooling;
3. potential demand for useful heat and cooling requiring additional high-efficiency cogeneration;
4. graphical illustration of existing and potential heat and cooling demand spots, existing and planned district heating and cooling infrastructure and potential in the form of a computerised map;
5. energy efficiency potential of the existing district heating and cooling infrastructure;
6. possible barriers to exploiting the potential of high-efficiency cogeneration and efficient district heating and cooling and recommendations on how to increase the share of CHP, district heating and district cooling;
7. cost-benefit analysis in order to identify the most resource- and cost-efficient solutions to meet the demand for heat and cooling;
8. achievable primary energy savings and reductions in greenhouse gases.

The project outcomes have been translated into the following outputs:

- computerised, interactive maps indicating current heat demand and heat demand in 2025 (in two scenarios), existing district heating and cooling networks, estimated waste heat potential and other such supply possibilities, technical and economic potential for efficient district heating and cooling and the application of high-efficiency cogeneration;
- a report for presentation to the European Commission in line with Article 14 of the Energy Efficiency Directive.

2 Heat and cooling demand in Austria

2.1 Heat and cooling demand in Austria – status quo

This section provides a detailed, regionally disaggregated illustration of heat demand broken down by sector (industry, services, agriculture, households) and by local area where possible. Total demand is then broken down by varying temperature levels and heat densities for the other work packages.

2.1.1 Heat and cooling demand in the housing sector

2.1.1.1 Methodology

Regionally disaggregated heat and cooling demand in the housing sector at the current time and in the scenarios for 2025 and beyond (see Section 2.2) is calculated using the Invert/EE-Lab bottom-up techno-economic model. The energy calculation is performed in Invert/EE-Lab by way of thermodynamic/physical mapping of buildings. The calculation of end energy demand is based on the Austrian pre-standards ÖNORM B 8110-5 2007, ÖNORM B 8110-6 2007, ÖNORM H 5055 2008 and ÖNORM H 5056 2007. The systematic user factor is integrated in the form of the difference between the indoor temperature and the 20°C temperature stipulated by the standard (Müller and Biermayr, 2010).

The **data basis** used for the aggregated data on existing buildings and heating systems and the accompanying national energy consumption is the available publications of Statistik Austria. As regards disaggregated data, the authors' databases were used. All data used was reconciled with national statistics. The following is a summary list of the main sources used:

- Building data: Statistik Austria (2004): '2001 building and housing census'; Statistik Austria (2006): document series 'Housing 2002' up to 'Housing 2010'; Statistik Austria (2003–2011): '2001 Workplace Census'; Statistik Austria: 'A look at the municipality: 4.27 completed residential buildings' and 'Characteristics: buildings and housing'; Statistik Austria (2009c): 'Construction of buildings and housing: construction permits and completions 2002–2011'; Statistik Austria (2011): 'Heating 2003/2004, 2005/2006, 2007/2008, and 2009/2010'.
- Energy consumption and energy consumption structures: Statistik Austria (2005): '2008 useful energy analysis'; micro-census surveys by Statistik Austria; Statistik Austria 2009: 'Energy usage of households 2003/2004, 2005/2006, 2007/2008 and 2009/2010'.

The year 2008 was selected as the baseline year for the base data. Using the base data and base calibration (based on Müller et al., 2014), the calibration data for dynamic development were updated using the 2008–2012 sample period (for the scenario development methodology, see Section 2.2.1). This report uses data from Statistik Austria's 2013 Energy Balance Sheet as the basis for model calibration up until the year 2012.

Table 2-1 indicates the current number of buildings and residential units, broken down by three construction periods, and their renovation status in the model calibration used.

Table 2-1: Number of buildings and residential units in 2008

	1000 buildings	1000 residential units
Residential buildings, pre-1945, unrenovated 1)	228	523
Residential buildings, pre-1945, renovated 2)	146	336
Residential buildings, 1945–1980, unrenovated 1)	448	921
Residential buildings, 1945–1980, renovated 2)	307	648
Residential buildings, 1981–2000, unrenovated	492	928
Residential buildings, 2001–2020, unrenovated	112	208
Non-residential service buildings, pre-2010	145	

1) unrenovated: no measures implemented in the building shell after 1994
2) renovated: measures implemented (including non-thermal measures) since 1995

The **stock of buildings** in Austria was mapped in accordance with the following groups:

- Residential buildings (92 building categories):
  - 4 building sizes (detached house, semi-detached house, small apartment building, large apartment building)
  - 8 construction periods (pre-1919, 1919 to 1944, 1945 to 1960, 1961 to 1970, 1971 to 1980, 1981 to 1990, 1991 to 2002 and new-builds)
  - Renovated buildings and unrenovated buildings
- Service buildings (45 building categories):
  - 7 types (hotels or similar buildings, offices, retail or wholesale buildings, transport or press buildings, workshops, industrial buildings or warehouses, buildings for cultural or leisure use as well as education and health, other buildings)
  - 1 to 4 construction periods (broken down by type)
  - 1 to 3 size classes (broken down by type)

Secondary residences and non-registered residences are not included in the data pool used. On the basis of plausibility estimations, these two groups were estimated to have an annual energy demand for heating and hot water of around 2.5 % of the energy demand of primary residences. This additional energy demand is smaller than the uncertainty range for primary residences (and its proportion of the energy balance). As such, secondary residences and non-registered residences were not modelled separately, but were instead taken into account in the results by way of model calibration.

In order to be able to perform a **regional analysis** of heat demand, the residential areas (permanent residential areas, Statistik Austria, 2008) were fitted to a 250x250m grid, with the number of inhabitants fitted to a 1x1km grid (Statistik Austria, 2006). The developed algorithm transfers the building structure (residential units, construction period, building type, number of residential units in order of size, source of heating energy etc. at municipality level for all 2380 municipalities, GWZ 2001, Statistik Austria) as well as workplaces and employees according to company size and ÖNACE classification at municipality level (ASZ 2001, Statistik Austria, 2009c) to a 50x50m grid using tangential surfaces. Figure 2-1 illustrates the residential area in Austria according to Statistik Austria, as used as a basis in this project.

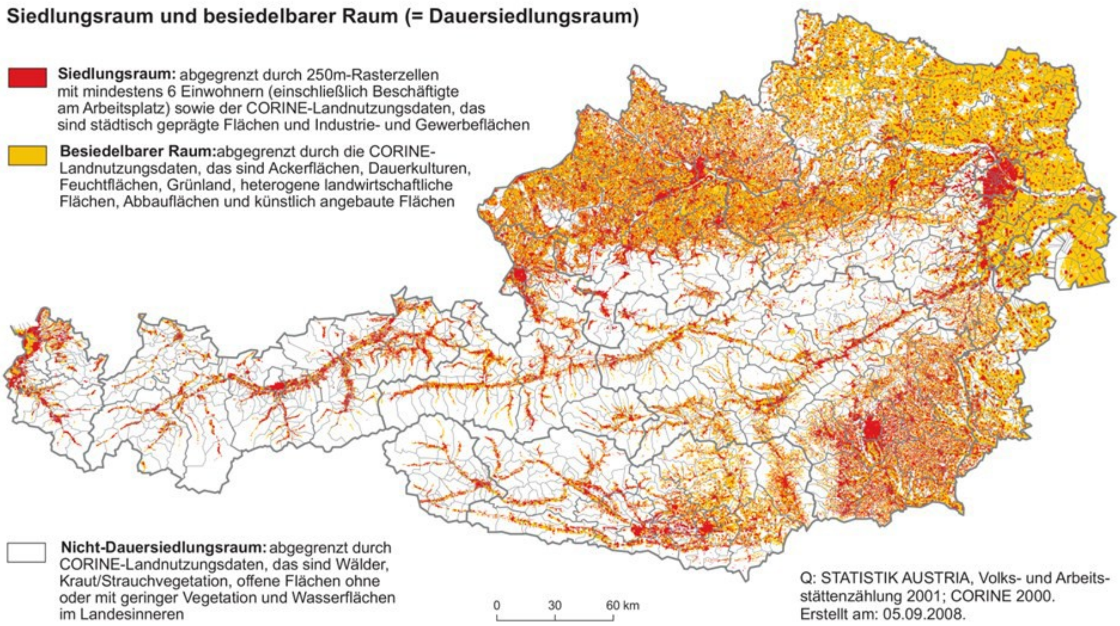


Figure 2-1: Permanent residential area in Austria (Source: Statistik Austria)

Siedlungsraum und besiedelbarer Raum (= Dauersiedlungsraum)	Residential areas and inhabitable areas (= permanent residential areas)
Siedlungsraum: abgegrenzt durch 250m-Rasterzellen mit mindestens 6 Einwohnern (einschließlich Beschäftigte am Arbeitzplatz) sowie der CORINE-Landnutzungsdaten, das sind städtisch geprägte Flächen und Industrie- und Gewerbeflächen	Residential areas: delineated using 250 m grid cells with at least 6 inhabitants (including employees at places of work) and using the CORINE land usage data, this term refers to urbanised areas and industrial and commercial areas
Besiedelbarer Raum: abgegrenzt durch die CORINE-Landnutzungsdatenm, das sind Ackerflächen, Dauerkulturen, Feuchtflächen, Grünland, heterogene landwirtschaftliche Flächen, Abbauflächen und künstlich angebaute Flächen	Inhabitable areas: delineated using the CORINE land usage data, this term refers to arable land, permanent crops, wetlands, grassland, heterogeneous agricultural land, quarries and artificially cultivated land
Nicht-Dauersiedlungsraum: abgegrenzt durch CORINE-Landnutzungsdaten, das sind Wälder, Kraut/Strauchvegetation, offene Flächen ohne oder mit geringer Vegetation und Wasserflächen im Landesinneren	Non-residential areas: delineated using the CORINE land usage data, this term refers to forests, undergrowth/scrubland, open areas with or without minimal plant life and inland bodies of water
Q: STATISTIK AUSTRIA, Volks- und Arbeitsstättenzählung 2001; CORINE 2000. Erstellt am: 05.09.2008.	Source: STATISTIK AUSTRIA, 2001 Population and Workplace Census; CORINE 2000. Created on 05/09/2008.

The definition of plot ratio given in the Energy Efficiency Directive, i.e. the ratio of the building floor area to the land area in a given territory, is not entirely clear as the size of the 'given territory' is not defined. The grid-cell-based approach that has been selected results in a large surface area being classified as built-up, particularly in sparsely populated regions.

The building density[1] resulting from the approach selected is in many cases lower than the values calculated in other studies (see Blesl, 2002). In order to compensate for this error, a second building density variant is also calculated (hereafter referred to as 'compact residential area'). This involves the 50x50m grid points, which are allocated a plot ratio of below 0.05 in line with the model imposed, being gradually (in three stages) divided into grid points with a higher building density. A restriction is

[1] In this project, the terms 'plot ratio' (as found in the Energy Efficiency Directive) and 'building density' are used interchangeably.

applied whereby the building density of the grid points may not increase by more than 75 % per stage in relation to the calculation method without error compensation. Below, only the results obtained using the compact residential area approach are used for analysis.

2.1.1.2 Demand for space and water heating in residential and non-residential buildings

The model calculations for the year 2012 result in a total heat demand in residential and non-residential buildings of 89 TWh (for a breakdown by building category, see Figure 2-10). Regionally disaggregated heat demand determined using the model can be found in Figure 2-2. The output data of the model enable an extremely varied analysis of heat demand in Austria to be carried out according to certain parameters, such as heat density, heat quantities and also plot ratio in line with the Energy Efficiency Directive, as required by the analyses in the following sections of this report.

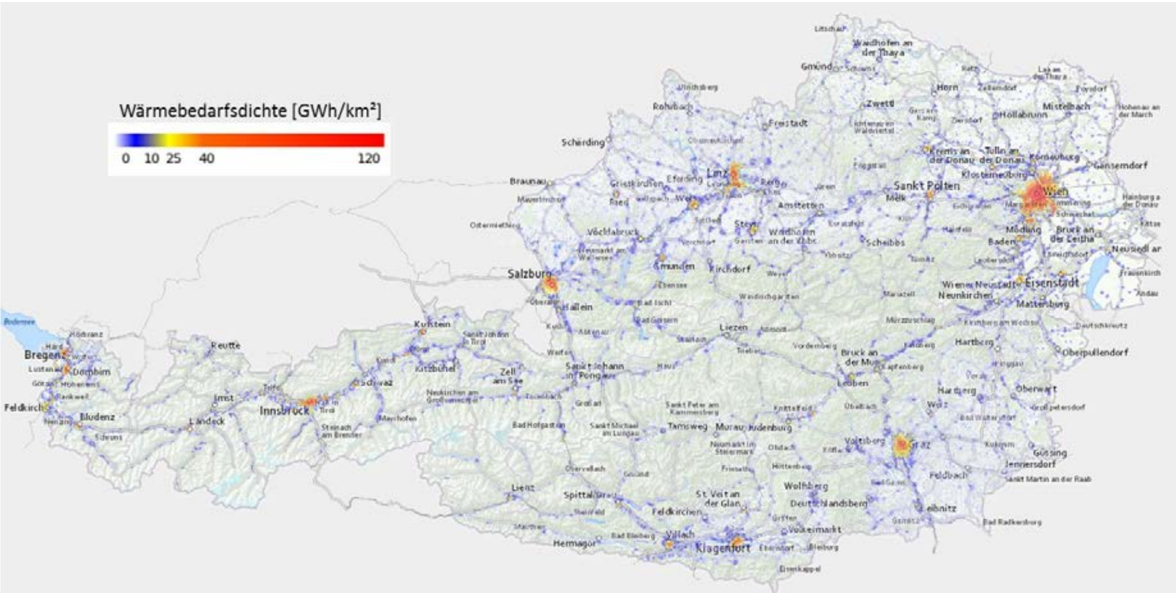
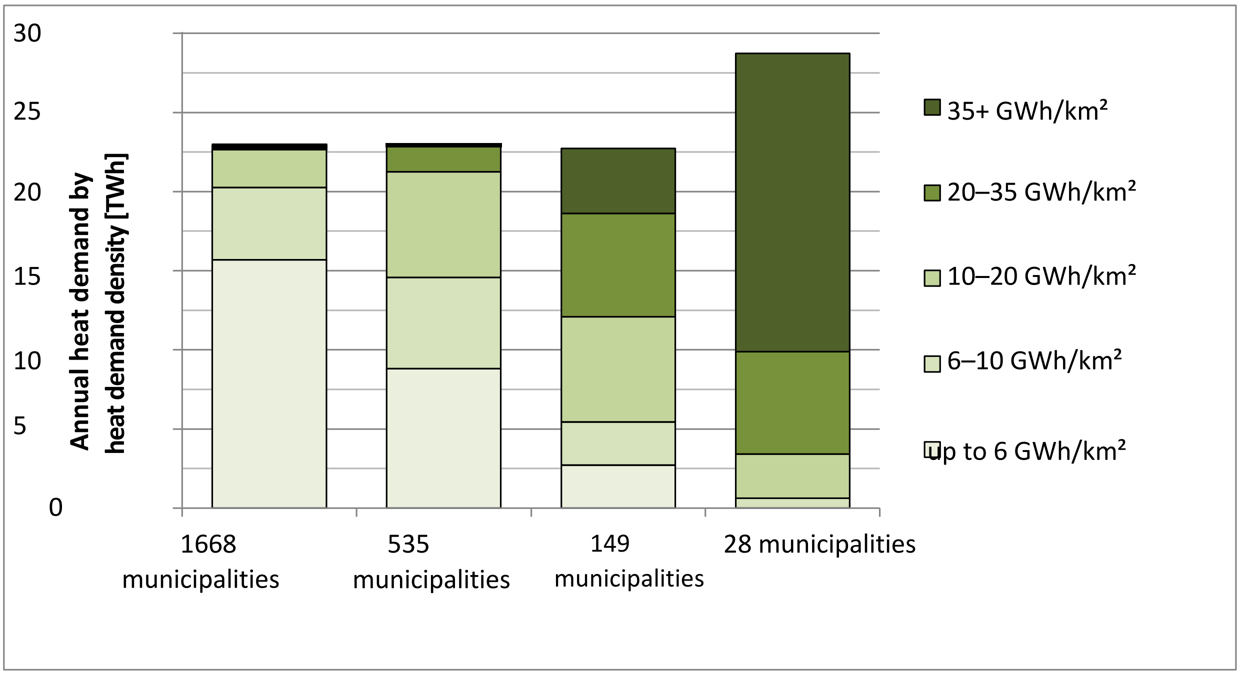


Figure 2-2: Building-related heat demand in Austria (source: Invert/EE-Lab, http://www.austrian-heatmap.gv.at)

Wärmebedarfsdichte [GWh/km2]	Heat demand density [GWh/km²]

A breakdown of energy demand according to regions with varying densities can be found in Figure 2-3. These analyses are then used to set appropriate thresholds for different heat density classes within the regions.



Municipalities sorted in ascending order according to annual heat demand (Vienna = 23 municipalities)

Figure 2-3: Breakdown of heat demand by region and heat density (source: Invert/EE-Lab)

In the further analyses performed for all Austrian municipalities, demand for space and water heating was sub-divided into six density classes ranging from less than 6 GWh/km² to over 60 GWh/km². The distribution of the total demand calculated for the year 2012 over these six density classes can be seen in Figure 2-4. Of the 89 TWh in total, 10 % can be allocated to areas with heat demand densities of below 10 GWh/km², the largest share of 62 % to areas with densities of between

10 and 35 GWh/km² and the remaining 28 % to areas with very high heat demand densities of over 35 GWh/km².

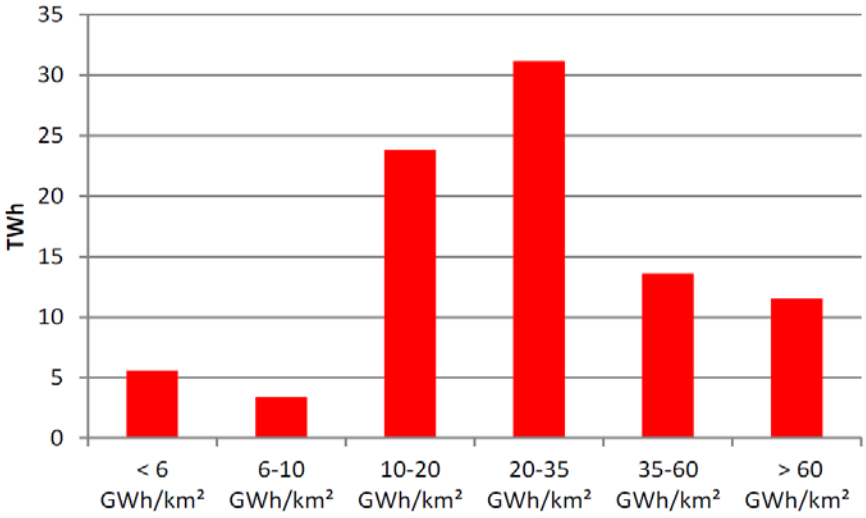


Figure 2-4: Allocation of heat demand for space and water heating for all municipalities to heat density classes (source: Invert/EE-Lab)

2.1.2 Heat and cooling demand in industry

2.1.2.1 Methodology

In this study, industrial energy demand is determined using three different methods. On the one hand, a top-down characterisation of the relevant energy demand (heat or cooling) was carried out on the basis of national statistics combined with sectoral studies. On the other, a bottom-up extrapolation of heat and cooling demand was conducted in two different ways. First, products of energetic significance at national level were linked to data on specific energy demand. In the second bottom-up variant, the energy demand of large companies was estimated on the basis of their individual systems, combined with the aggregated data for smaller companies. In accordance with the Directive, industrial and commercial zones with a heat and cooling demand of over 20 GWh/a must be included in the interactive map. Furthermore, it is necessary to perform a regional breakdown of industrial energy demand in order to calculate the technical and economic potential of district heating. To this end, the system-specific extrapolations are first tested for plausibility by comparing them with the other two methods.

In doing so, the system-specific demand extrapolation is also calculated in different ways in order to test the plausibility of each of the results. First, characteristic sectoral data is applied to the companies in the ETS. The composition of demand is also calculated on the basis of sector-specific data on the number of employees. Furthermore, research into system-specific data for the major companies was carried out.

2.1.2.2 Heat and cooling demand in the Austrian manufacturing sector

Figure 2-5 shows a distribution of heat and cooling demand in the field of manufacturing in Austria according to the sectors specified in the energy balance sheet. The data from the useful energy analysis form the basis for this. Only those use categories relevant to heat and cooling demand were taken into account. Furthermore, the resulting values were converted by way of estimated aggregated efficiency values per use category from end energy demand values into useful energy demand values, i.e. process-/usage-specific demand for heat or cooling. It emerges that the manufacture of paper and cardboard, including printing, is the area with the greatest demand for thermal energy, requiring approximately 11 TWh/a. Much further down in the ranking come the iron and steel manufacturing sector, stone, non-metallic minerals, and the chemicals industry.

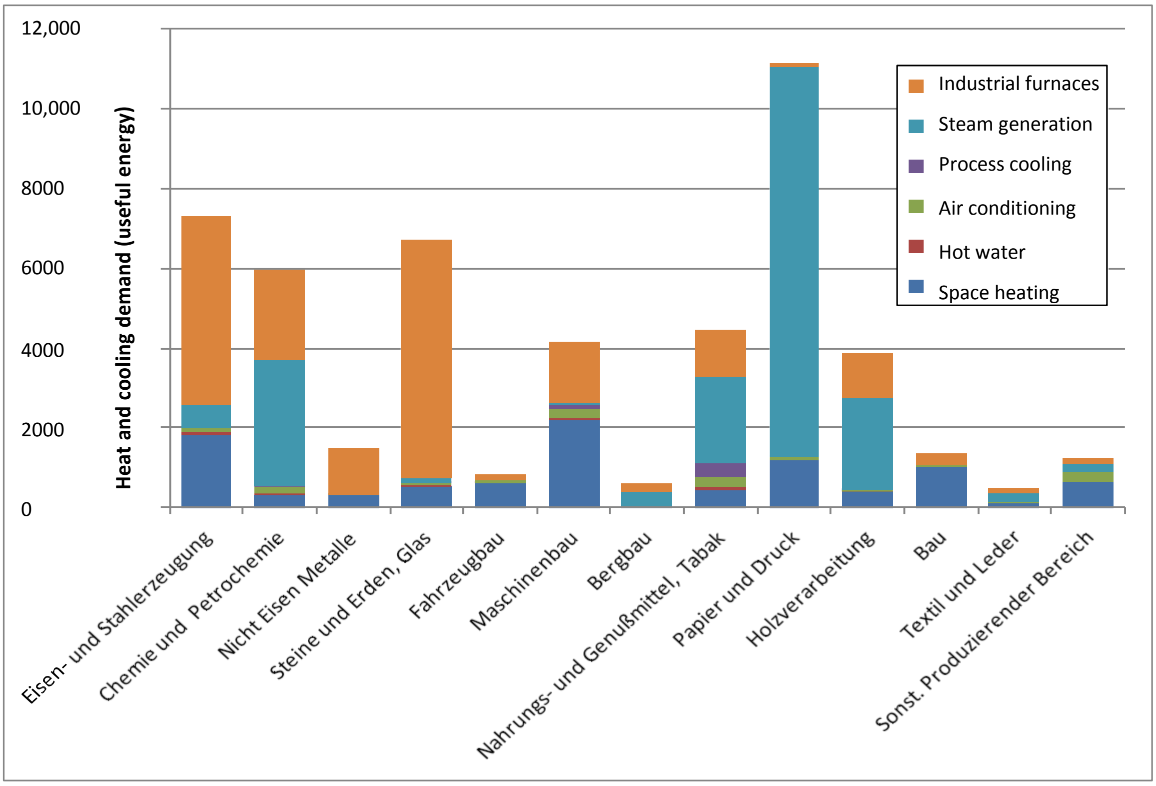


Figure 2-5: Heat and cooling demand of the goods manufacturing sector in Austria in the year 2012 (own calculations on the basis of useful energy analysis from Statistik Austria, 2013a)

Eisen- und Stahlerzeugung	Iron and steel production
Chemie und Petrochemie	Chemicals and petrochemicals
Nicht Eisen Metalle	Non-ferrous metals
Steine und Erden, Glas	Non-metallic minerals
Fahrzeugbau	Vehicle construction
Maschinenbau	Manufacture of machinery and equipment n.e.c.
Bergbau	Mining
Nahrungs- und Genußmittel, Tabak	Foodstuffs, tobacco
Papier und Druck	Paper and printing
Holzverarbeitung	Wood processing

Bau	Construction
Textil und Leder	Textiles and leather
Sonst. Produzierender Bereich	Other manufacturing sectors

A breakdown of current heat demand by temperature level can be found in Figures 2-6 and 2-7 below. This was performed on the basis of data generated by various studies from Germany (Nast, 2010; Wagner, 2002; Eikmeier, 2005 and Hofer, 1995). These were applied to the Austria-specific breakdown of heat demand according to the different usage types per sector. It emerges that around 65 % of industrial heat demand comes in at temperatures of between 20°C and 500°C, with the largest proportion of that falling in the range between 100°C and 500°C (27 %). Technically speaking, there is potential for application of CHP systems at temperatures between 20°C and 500°C; exergetically speaking, the most suitable temperature range is 100°C to 500°C, as both solar thermal energy and traditional heat pumps suffer significant efficiency losses in this range.

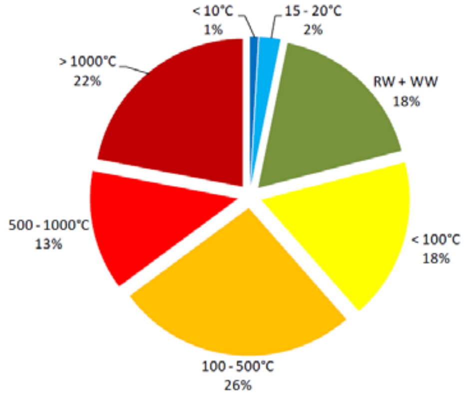
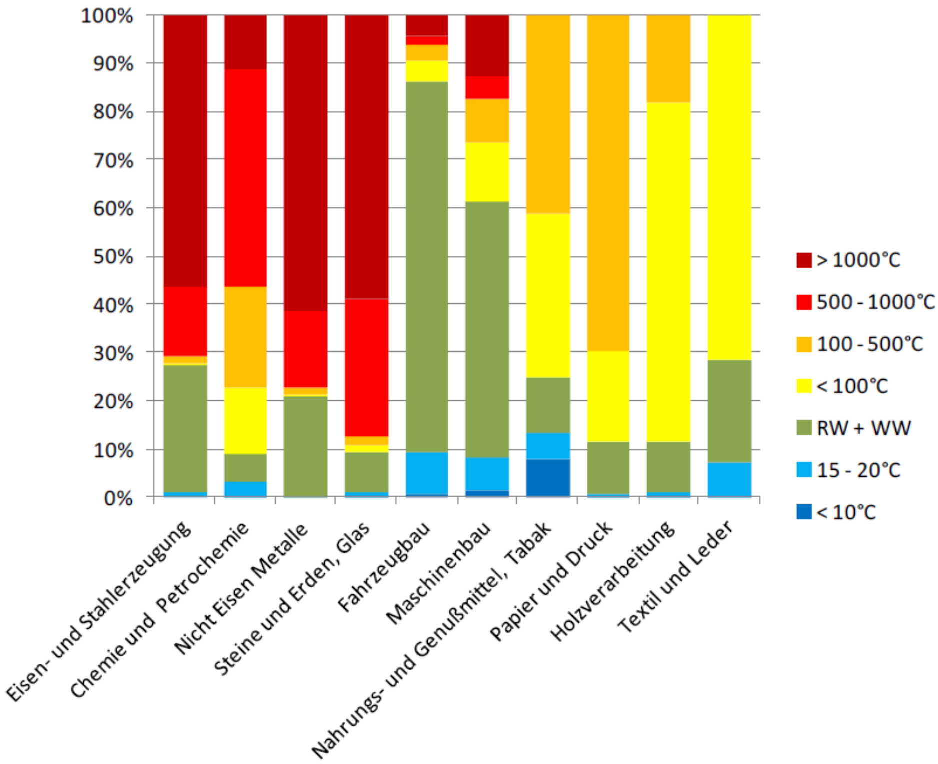


Figure 2-6: Breakdown of total heat demand in the Austrian goods manufacturing sector by temperature level (own calculations on the basis of data from Statistik Austria, 2014 and Nast, 2010)

On the basis of the temperature distribution for the individual sectors, it appears that it is primarily the sectors producing raw materials and semi-finished goods for further processing that require heating at temperatures of over 500°C. This temperature range is relevant to the analysis of the potential for application of efficient district heating in that waste heat from such facilities usually reaches temperature levels that may be usable in district heating.



Eisen- und Stahlerzeugung	Iron and steel production
Chemie und Petrochemie	Chemicals and petrochemicals
Nicht Eisen Metalle	Non-ferrous metals
Steine und Erden, Glas	Non-metallic minerals
Fahrzeugbau	Vehicle construction
Maschinenbau	Manufacture of machinery and equipment n.e.c.
Nahrungs- und Genußmittel, Tabak	Foodstuffs, tobacco
Papier und Druck	Paper and printing
Holzverarbeitung	Wood processing
Textil und Leder	Textiles and leather

Figure 2-7: Breakdown of heat demand in the Austrian goods manufacturing sector by temperature level (own calculations on the basis of data from Statistik Austria, 2014 and Nast, 2010)

2.1.2.3 Number of employees in the manufacturing sector

Goods manufacturing is an important mainstay of the economy in Austria. In 2012, approximately 560,000 people were employed in the manufacturing sector, equivalent to 13 % of the total national workforce of 4.1 million. Figure 2-8 shows a breakdown of employees per area of goods manufacturing. The structure used here is in line with the international energy balance sheet structure in order to enable a comparison with the energy demand values. These figures indicate that, with a share of 25 %, machinery and equipment manufacturing firms are the main employers in the manufacturing sector. If related sectors are included, i.e. metal products and vehicle manufacture, the processing of metals into end products accounts for 50 % of the workforce in the manufacturing sector.

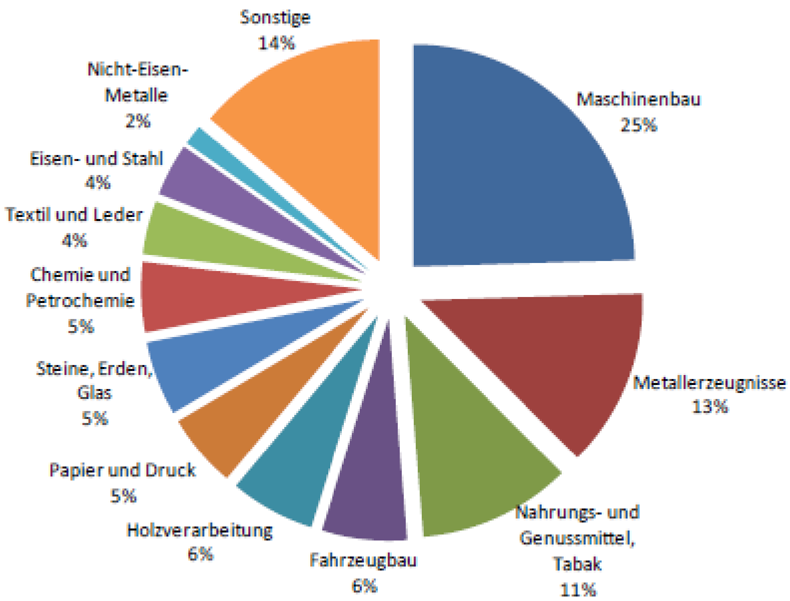


Figure 2-8: Breakdown of employees in goods manufacturing by sector for 2012 (source: own analysis on the basis of data from Statistik Austria, 2013 and documentation on the energy balance sheet [Statistik Austria, 2014c])

Sonstige	Other
Nicht-Eisen-Metalle	Non-ferrous metals
Eisen- und Stahl	Iron and steel
Textil und Leder	Textiles and leather
Chemie und Petrochemie	Chemicals and petrochemicals
Steine, Erden, Glas	Non-metallic minerals

Papier und Druck	Paper and printing
Holzverarbeitung	Wood processing
Fahrzeugbau	Vehicle construction
Nahrungs- und Genussmittel, Tabak	Foodstuffs, tobacco
Metallerzeugnisse	Metal products
Maschinenbau	Manufacture of machinery and equipment n.e.c.

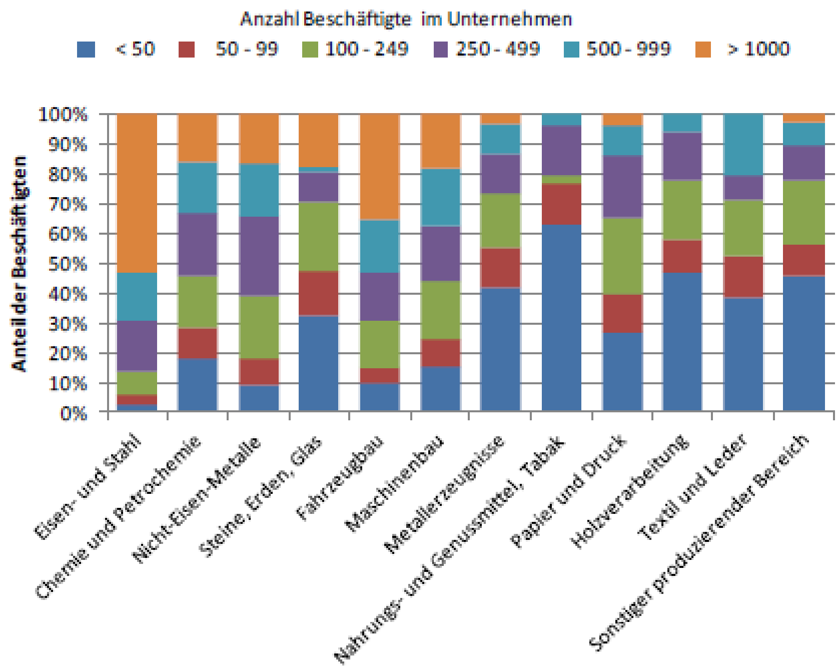


Figure 2-9: Breakdown of all employees per sector according to company size class (source: own analysis on the basis of data from Statistik Austria, 2013 and documentation on the energy balance sheet [Statistik Austria, 2014c])

Eisen- und Stahl	Iron and steel
Chemie und Petrochemie	Chemicals and petrochemicals
Nicht-Eisen-Metalle	Non-ferrous metals
Steine, Erden, Glas	Non-metallic minerals
Fahrzeugbau	Vehicle construction
Maschinenbau	Manufacture of machinery and equipment n.e.c.
Metallerzeugnisse	Metal products
Nahrungs- und Genussmittel, Tabak	Foodstuffs, tobacco
Papier und Druck	Paper and printing
Holzverarbeitung	Wood processing
Textil und Leder	Textiles and leather
Sonst. Produzierender Bereich	Other manufacturing sectors

2.2 Heat and cooling demand scenarios up to 2025 (and beyond)

In this section, two heat and cooling demand scenarios are developed taking special account of the construction of new buildings, renovation of residential buildings as well as changes in industry and commerce and in the energy sector. These scenarios are then used as a framework for assessing district heating and cogeneration potential. In line with the Energy Efficiency Directive, the analyses in this project cover the period up until 2025. However, developments in heat demand beyond the year 2025 are also relevant when it comes to properly assessing the usefulness of long-term investments.[2] As such, in the housing sector, heat and cooling demand scenarios up to the year 2050 are included. Heat and cooling demand in industry and business is only considered up until the year 2035 due to the high degree of uncertainty in these sectors compared to the housing sector.

2.2.1 Methodology for producing scenarios for heat and cooling demand in the housing sector

As already explained in section 2.1.1, both current and future heat and cooling demand in the housing sector is calculated using Invert/EE-Lab. The basic algorithm of the scenario development model is a stochastic, non-recursive, myopic, economic, nested logit model, which maximises the utility function of stakeholders (i.e. investors) in investment decision situations. The following building shell measures can be included in the model:

- insulation of the façade
- insulation of the top storey ceiling
- insulation of the bottom storey ceiling
- replacement of windows
- restoration of the façade without insulation.

The choice of heating system, which is also in principle modelled in the Invert/EE-Lab model, is not taken account of in this project as the focus is on heat demand and not on the heating system and energy source mix.

The following potential policy instruments can be implemented in the model:

- technological standards
- financial support
- mandatory implementation of heating systems using renewable energy
- taxes
- mandatory replacement of heating systems
- maximum funding budgets for new builds, building renovation and heating systems.

In addition to the policy instruments and renovation measures listed above, both climate change at municipality level (Institute for Metrology, REMO-UBA model, 2010) and future developments in residential units at district level until 2030 (Blanika, 2007) were taken into account.

Additional input values include historical developments in residential units, energy sources, buildings according to construction periods (2002–2011) and energy demand at individual state level (micro-census 2002–2011, Statistik Austria).

[2] Similar suggestions were also made during the stakeholder workshops organised in connection with this project.

2.2.2 Business-as-usual (BAU) scenario

The business-as-usual (BAU) scenario is based on the assumption that the measures and energy policy climate in place up until the start of 2014 will remain unchanged, with those measures already adopted being neither reinforced nor diminished.[3]

This concerns in particular the provisions in relation to building regulations, residential building subsidies etc. The following figures show the outcomes of the BAU scenario as regards end energy demand for space heating and hot water in the Austrian building stock: on the basis of a space heating and hot water demand of just below 100 TWh in the baseline year 2012, in this scenario energy demand falls to approximately 55 TWh by 2050. Around two thirds of this energy demand is attributable to residential buildings. Figure 2-10 shows a breakdown of the modelled heat demand by building category. In 2025, end energy demand for heating purposes is estimated at approximately 81 TWh (useful energy demand stands at 77 TWh).

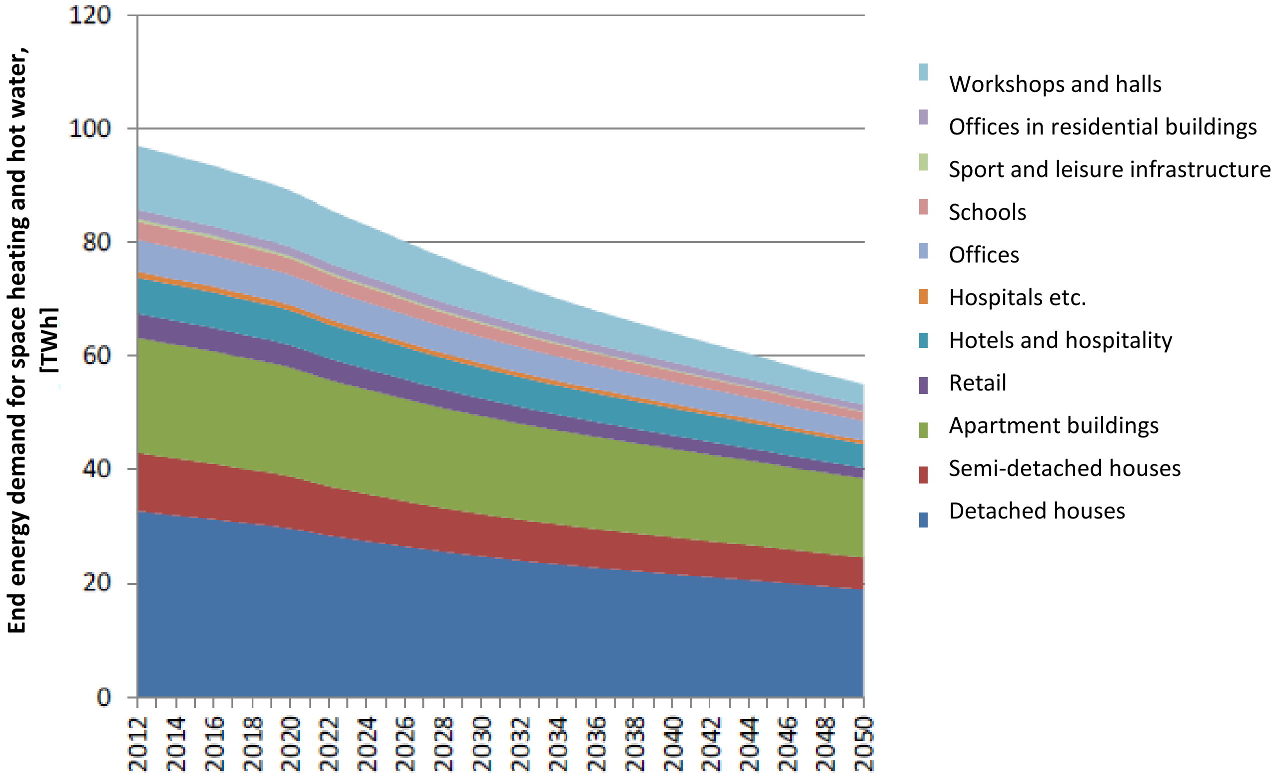


Figure 2-10: End energy demand for space heating and hot water, broken down by building category; BAU scenario (source: Invert/EE-Lab)

[3] In order to ensure a high level of consistency with other relevant energy scenarios, assumptions are included from the project 'Establishment of energy input parameters and scenarios in order to meet the reporting obligations of the monitoring mechanism', which is currently being conducted at the request of the Ministry of Agriculture, Forestry, Environment and Water Management. The BAU scenario set out here corresponds to the 'with existing measures' scenario from the aforementioned project.

2.2.3 High-efficiency scenario

In the high-efficiency scenario, it is assumed that an ambitious package of measures to increase energy efficiency both in the housing sector and in commercial buildings is introduced. It is based on the assumption that coordinated measures are implemented in order to eliminate the numerous barriers to high-quality building renovation. This includes changes to tenancy and residential property law and to building regulations, promotion of energy consulting, building-specific renovation road maps etc. On the basis of the selected assumptions, an end energy demand for heating purposes of 75 TWh is calculated for 2025 (useful energy demand stands at 65 TWh, i.e. -17 % compared to BAU).

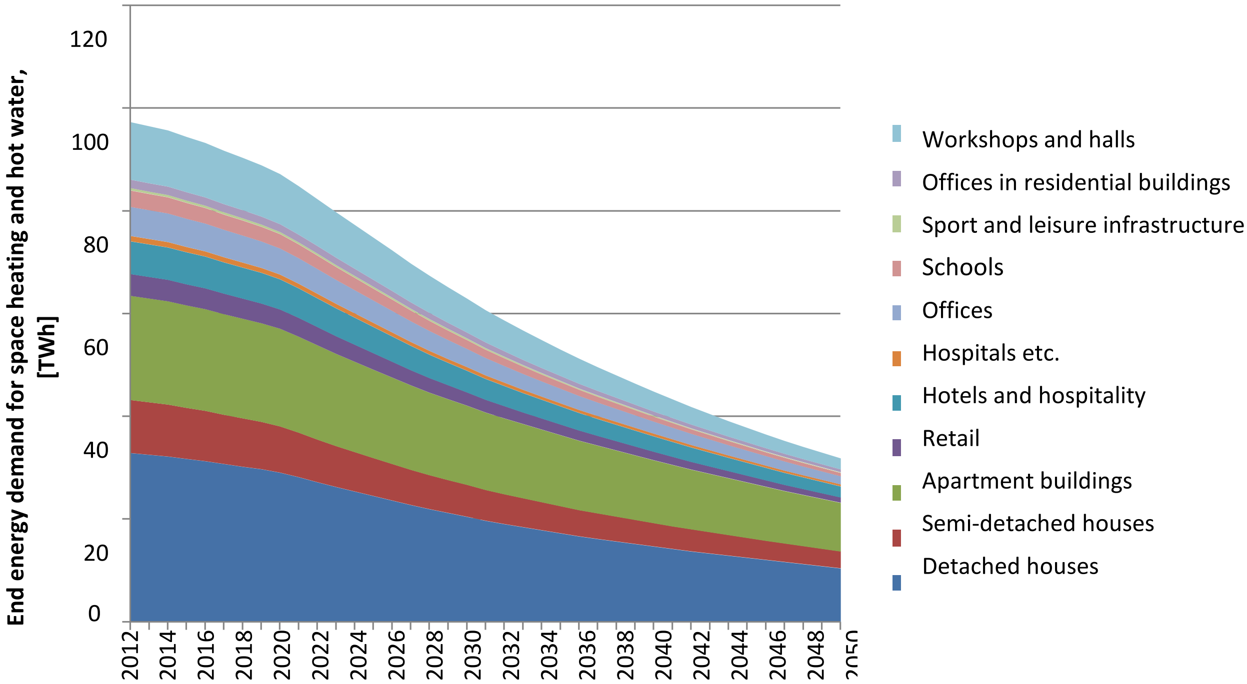


Figure 2-11: End energy demand for space heating and hot water, broken down by building category; high-efficiency scenario (source: Invert/EE-Lab)

2.2.4 Scenarios for heat and cooling demand in industry

The heat and cooling demand scenarios are based on the status quo from 2012, as described in Section 2.1.2. In order to create an interactive, online map, both the status quo and the scenarios were calculated for individual sites, although it goes without saying that it was not possible to conduct detailed analyses of each of these locations in the context of this project. Instead, an aggregated approach was used as described below. In this study, the ETS Registry is used as an indicator of the relevance of individual industrial sites to the investigation in question. In addition, further calculations are carried out for certain sites on the basis of actual emissions between 2008 and 2011. For sites with a large share of total heat demand, and for sectors with a high degree of inhomogeneity, the calculations are performed on the basis of production quantity/capacity. In the first case, the share of emissions from internal heat supply is estimated, and useful heat demand is calculated on the basis of fuel consumption. This is primarily done using data from Statistik Austria (2014) and UBA (2014).

In the second case, production quantities[4] are combined with literature values on relative heat demand.[5] Changes in this estimated current heat demand, taking into account efficiency developments in the individual sectors (on the basis of Krutzler et al., 2013), are calculated for the year 2025, both for a business-as-usual scenario and a high-efficiency scenario.

As regards this extrapolation, it should be noted that the use of product-/sector-specific parameters only reflects site-specific conditions averaged across the entire sector, meaning that the estimates for individual sites may be prone to error. Furthermore, parameters from Germany and other countries are used in many cases where there are no such values available for Austria.

Scenarios for the future development of heat and cooling demand in Austrian industry are, like in the space heating and hot water sector, based on the project 'Establishment of energy input parameters and scenarios in order to meet the reporting obligations of the monitoring mechanism'. In order to perform a deeper disaggregation of the results from industry, results from Fleiter et al. (2013) were applied to Austria. The higher degree of detail in this study makes it easier to subsequently convert the results for the Austrian territory. In doing so, similar diffusion rates for energy-efficient technology and efficiency measures are assumed as for Germany. The outcomes of both the BAU and high-efficiency scenarios were also discussed bilaterally with stakeholders. The described extrapolations were presented to companies and sector representatives, and in certain cases they were classed as being infeasible. In cases where companies provided specific maximum potential savings at their sites for the period up until 2025, these data were included in further calculations.

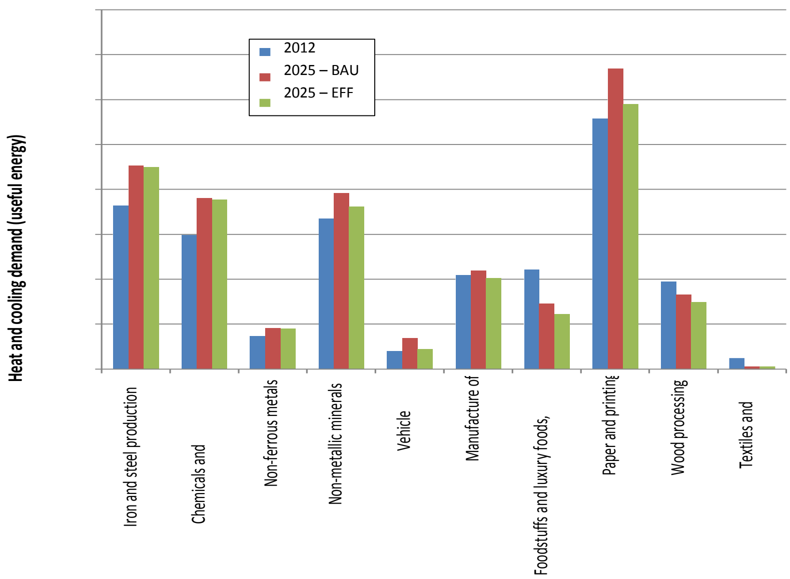


Figure 2-12: Heat and cooling demand by sector in the baseline year 2012, business-as-usual (BAU) scenario and high-efficiency scenario (EFF) for the year 2025 (source: own analyses on the basis of data from Krutzler et al., 2013)

[4] Sources primarily comprise the annual reports of professional associations, BAT documents and UBA, 2004.

[5] Values are mainly derived from the following two sources: Fleiter et al. (2013) and Neelis et al. (2007).

2.3 Heat load curve for regions and individual buildings

In order to calculate economic potential, heat load profiles were developed both for individual buildings and for potential district heating regions alongside calculations of heat demand. Compared to individual buildings, heat loads for heating grids tend to be characterised by a greater number of full-load hours. This is on the one hand the result of a certain smoothing effect due to various temporal fluctuations in demand from district heating customers, and on the other it is determined by storage effects within the heating grid itself.

2.3.1 Heat load profiles in district heating regions

The heat load profile was determined using a linear regression model, which was calibrated based on historical measurement data on heat demand in exemplary district heating networks. The following equation was used to estimate the heat load ($P_{th,i}$) in hours i:

$$P_{th,i} = c_0 + \sum_{n=1}^{N} c_n T_i^n + \sum_{m=1}^{M} c_{N+m} D_{i,m}$$

Equation 2-1

$P_{th,i}$ Average heat load in hours *i*

c_0 Constant – indicates the offsetting of heat demand for hour i

c_x Coefficients determined using the regression

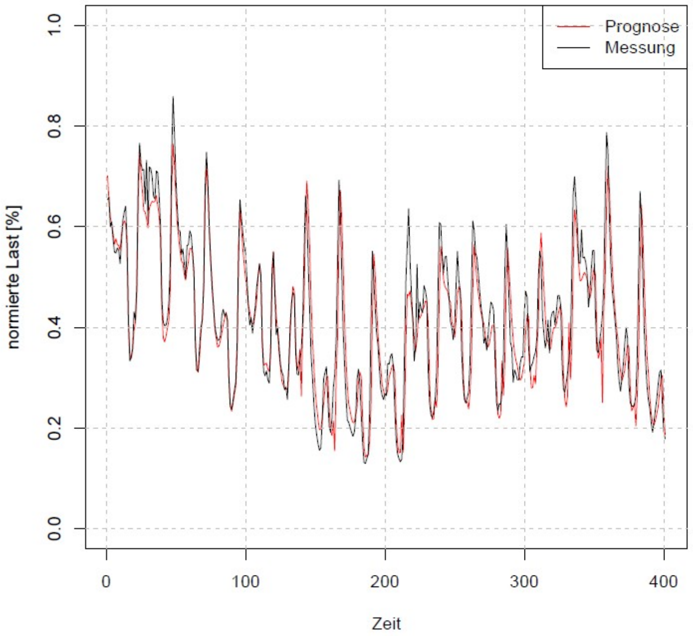
D Dummy variables and additional influencing factors for bank holidays, Saturdays and Sundays

M Number of dummy variables and additional influencing factors

T_i Temperature at hour *i*

N Number of powers with which the temperature is entered into the model

Analysing each hour individually enables the change in load throughout the day to be modelled. Changes in demand within the same hour primarily depend on the outside temperature T. In order to illustrate non-linearities, the model includes the temperature as a term to the power of four. In addition, further influencing parameters D are fed into the model (e.g. Saturday Sunday and bank holidays, seasonal variations, daily average temperatures, lags). The coefficients c_x of the influencing parameters are determined in such a way that deviations from historical measurement values are minimised. The various models achieve a high degree of consistency with measurement values in line with statistical criteria (adjusted coefficient of determination R^2 in the range of 0.98). Figure 2-13 shows a graphical comparison of the standardised heat load of a measured district heating region with model results over 400 hours. Figure 2-14 shows a comparison of the duration curves for measured and simulated values for a district heating region.



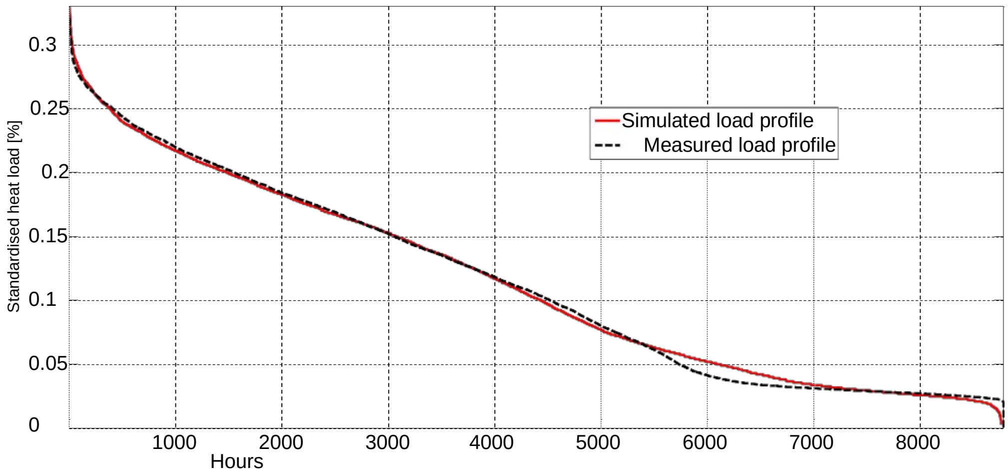
Prognosis

Measurement

Standardised load [%]

Time

Figure 2-13: Comparison of model prognoses and measurement values for a measured district heating region (source: own calculations)



0

Figure 2-14: Comparison of measured and modelled heating duration curves (source: own calculations)

The model results were then applied to historical temperature data from between 2006 and 2011 in the potential district heating regions (see Section 4.3). In order to calculate the representative duration curves, the year with the smallest deviation from the annual average total of full-load hours in the period under consideration was used for each region. The resulting full-load hours for heat demand in potential district heating regions come to between 2350 h/a and 3150 h/a. The selected load profiles are used to determine economic potential as described in Section 5. In this project, no attempt was made to modify the load profiles in line with future developments in heat demand. As such, heat demand primarily varies between the two scenarios in terms of the total level of demand, but not in terms of its development over time.

2.3.2 Heat load profiles for individual buildings

In order to estimate the cost-effectiveness of building-related cogeneration, simulated load profiles from previous projects are used. In addition, four load profiles representing each of the different building types are used.

Load profile 1: bakeries, launderettes

Load profile 2: accommodation, new apartment buildings, business establishments

Load profile 3: restaurants, guest houses, old apartment buildings, banks and other services, efficient detached houses

Load profile 4: old detached houses, commercial buildings, workshops

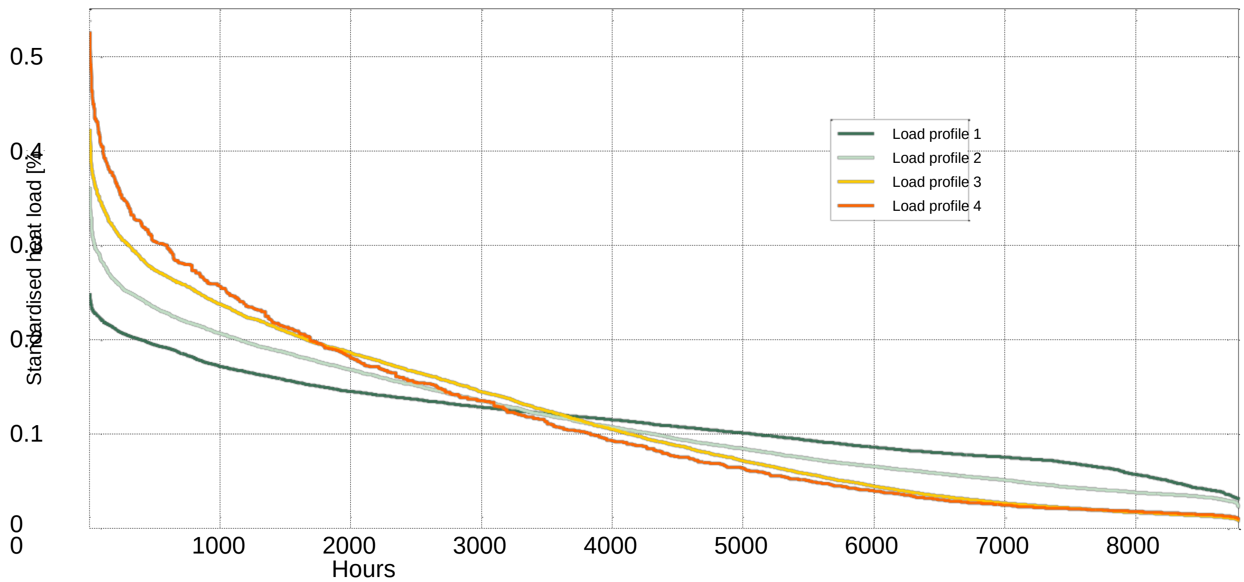


Figure 2-15: Assumed heat load duration curves for the different building types

Figure 2-15 shows the different load duration curves used to calculate the cost-effectiveness of building-related cogeneration in Section 5.

3 Fulfilment of heat and cooling demand in Austria – status quo

This section provides information on the current supply structure and the relevant supply units. The technologies used for centralised and decentralised units as well as supply grids are described in as much detail as possible.

3.1 Fulfilment of building-related demand in Austria

Figures 3-1 and 3-2 illustrate historical developments in the fulfilment of space heating and hot water demand in Austria as well as the status quo, the resulting trend line and developments in the BAU scenario according to the Invert/EE-Lab model.

Figure 3-1 presents changes in end energy demand as modelled for the BAU scenario for the energy sources covering the greatest proportion of heat demand, and Figure 3-2 shows developments for energy sources which currently cover a relatively small share of demand. These figures demonstrate that, on the basis of the model results, a drop in energy demand for heating and a rise in the share of renewable energy sources is to be expected simply through the continuation of existing policies. In 2012, the share of decentralised, renewable heating systems in Austria stood at around 23 % of end energy demand for space heating and hot water. It should once again be noted that in this project, potential for district heating and cogeneration will solely be determined on the basis of changes in heat demand as calculated by the Invert/EE-Lab model. The economic potential of various technologies and energy sources is calculated using the methodology described in Section 6.3.

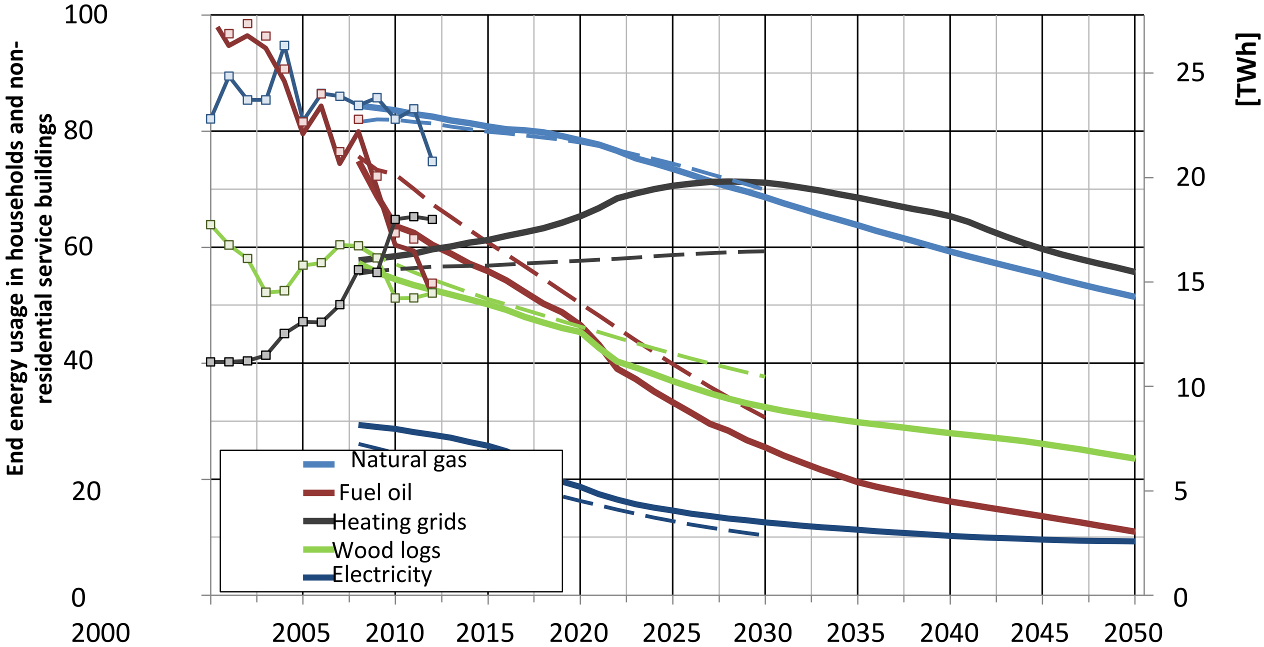


Figure 3-1: End energy demand for space heating and hot water, broken down by primary energy sources, BAU scenario; dashed line = historical trends (source: Statistik Austria, Invert/EE-Lab)

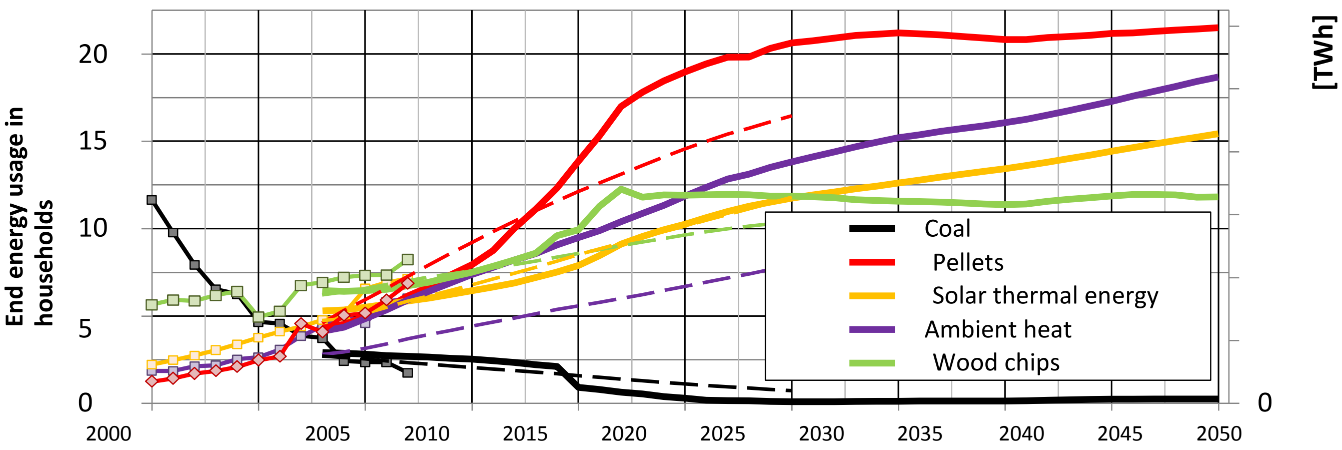


Figure 3-2: End energy demand for space heating and hot water, broken down by energy sources fulfilling a smaller share of energy demand; BAU scenario; dashed line = historical trends (source: Statistik Austria, Invert/EE-Lab)

3.2 Coverage of grid-connected demand in Austria

This section provides an analysis of past developments in the Austrian district heating sector and in existing grids, where available, up until 2012. In addition, the main heat supply areas in Austria are then mapped for each individual region. Information on different grid structures and relevant parameters are compiled and compared. The supply structure (waste incineration, biomass plants, heating plants and cogeneration plants with varying energy sources) in these areas is investigated and mapped.

3.2.1 Developments in the district heating sector and current state of play

The data from the energy balance sheet drawn up by Statistik Austria indicates that heating grids have grown increasingly significant in Austria since the 1970s. Between 2000 and 2012, district heating production in Austria rose by 74 %, and has demonstrated a positive trend overall. The peak in 2010 was due to particularly cold weather that year, with a 13 % rise in heating degree days compared to the long-term average, and particularly hot weather in the following year 2011, with 12 % fewer heating degree days compared to the long-term average. Grid losses throughout the entire district heating sector stand at around 8 % on average. With the residual distribution volume of around 21 TWh, it was possible to cover nearly 20 % of total heat demand in the household and services sectors using district heating in 2012. In the manufacturing sector, this share stands at 5 %, and in agriculture it is less than 4 %. District heating generation as illustrated in Figure 3-3 clearly demonstrates a more or less steady level of generation from CHP plants and heating plants using non-renewable energy sources, and a clear rise in generation from CHP plants and heating plants using renewable energy sources.

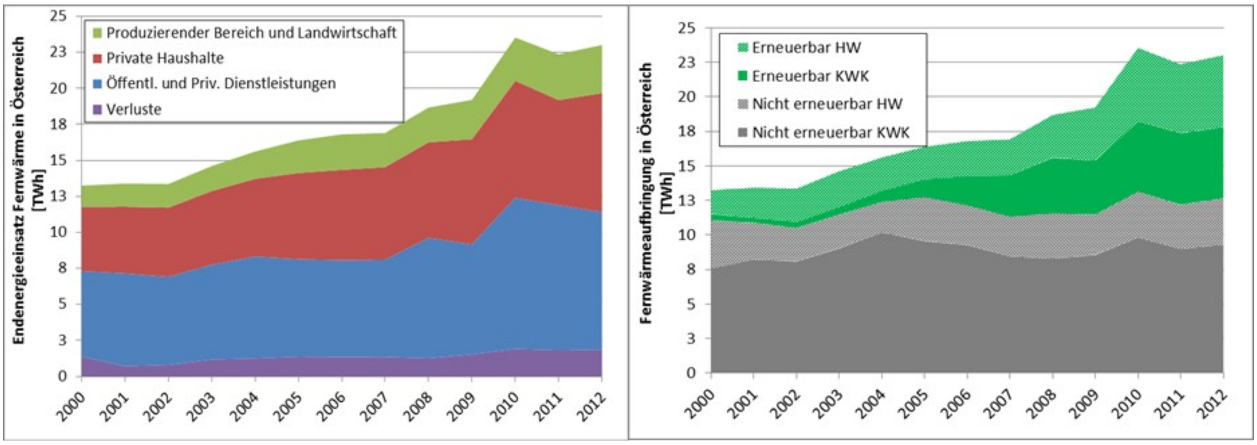


Figure 3-3: End energy usage and type of generation in the district heating sector in Austria (source: total energy balance for Austria (1970 to 2012), Statistik Austria)

Endenergieeinsatz Fernwärme in Österreich (TWh)	End energy usage for district heating in Austria (TWh)
Produzierender Bereich und Landwirtschaft	Manufacturing sector and agriculture
Private Haushalte	Private households
Öffentl. Und Priv. Dienstleistungen	Public and private services
Verluste	Losses
Fernwärmeaufbringung in Österreich (TWh)	District heating generation in Austria (TWh)
Erneuerbar HW	Renewable thermal power plants
Erneuerbar KWK	Renewable cogeneration
Nicht erneuerbar HW	Non-renewable thermal power plants
Nicht erneuerbar KWK	Non-renewable cogeneration

On the generation side, the rise in demand for district heating was therefore almost exclusively covered by the expansion of heating plants and CHP plants to include use of renewable energy sources, primarily biomass. The largest share of the biogenic energy sources is accounted for by wood waste, at over 79 %. The total share of renewable energy sources in district heating generation increased from 16 % in 2000 to 45 % in 2012. During this period, the share of heat generated in CHP plants always remained between 60 % and 70 %. Trends in generation for each of the energy sources are illustrated in Figure 3-4.

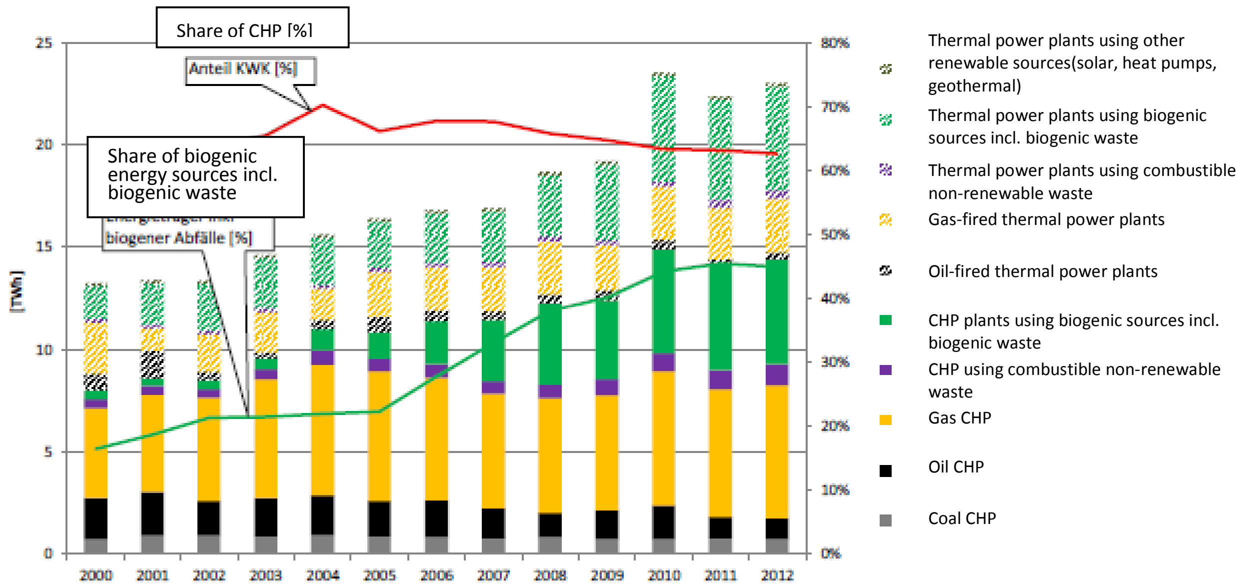


Figure 3-4: Share of energy sources in district heating generation (source: total energy balance for Austria (1970 to 2012), Statistik Austria)

The current situation as regards district heating supply for private households is based on the results of the housing survey forming part of the micro-census. According to this survey, 806,000 homes were supplied via district heating in 2012. That is equivalent to 22 % of primary residences in Austria. According to the Industry Association of Gas and Heating Companies, in order to achieve this, heating companies used a grid measuring roughly 4600 km in length to supply end consumers.

Figure 3-5 shows district heating energy end use broken down by each of the Austrian federal states. The distribution of grid-bound heating varies greatly between states. It should be noted that nearly a third of all district heating is supplied to homes in Vienna, followed by Lower Austria, Upper Austria and Styria. Vorarlberg and Burgenland occupy the bottom of the list. These two states also have the lowest supply volumes per inhabitant. Vienna and Carinthia boast the highest supply volume per capita. However, there has been an upwards trend in district heating supply in all federal states since 2000.

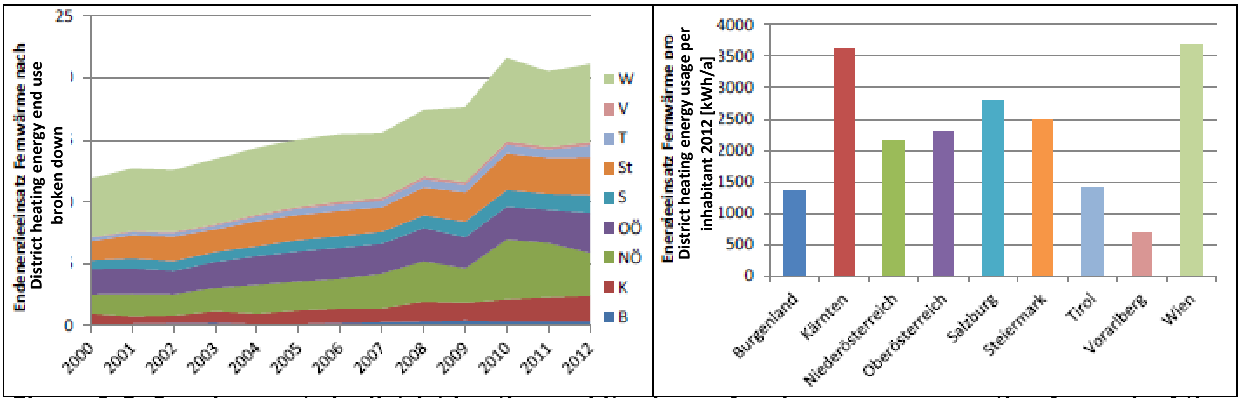


Figure 3-5: Developments in district heating and its share of end energy consumption for each of the federal states (source: District Heating Balance Sheet, Statistik Austria)

First graph	Second graph	English
W	Wien	Vienna
V	Vorarlberg	Vorarlberg
T	Tirol	Tyrol
St	Steiermark	Styria
S	Salzburg	Salzburg
OÖ	Oberösterreich	Upper Austria
NÖ	Niederösterreich	Lower Austria
K	Kärnten	Carinthia
B	Burgenland	Burgenland

3.2.2 Supply structure of district heating grids (generation facilities and companies)

A number of different heat sources can be used to supply district heating grids. These range from combined heat production in CHP plants, through heating plants, right up to industrial waste heat and the supply of heat generated through solar or geothermal energy or through heat pumps and electric direct heating systems. The following options are in principle available for district heating in Austria:

- heat from CHP plants using a range of fuels
- heat from waste incineration plants
- heat from heating plants using a range of fuels

- industrial waste heat
- geothermal heat
- solar thermal heat.

Since there are so many options, the supply structures of district heating grids vary greatly. In large cities, the grids are usually supplied by way of combined heat generation in **CHP plants** belonging to electricity providers. Increasingly, these large grids are also being supplied with heat from biomass plants or waste incineration. In addition, boilers are usually required in these cities to cover peak demand and to act as an outage reserve. In smaller municipalities, district heating grids are usually supplied by way of biomass heating plants or biomass CHP plants.

Of the 83 electricity-generating fossil fuel power plants in operation in Austria in 2012, nearly 80 % of the installed electrical capacity of 7 GW_{el} was generated by CHP plants (stock statistics, bottleneck capacity according to power plant type and size class, e-control, 2012a).

Of the nearly 500 biogenically powered plants, the share of CHP plants in the installed electrical capacity of 620 MW_{el} stands at approximately 76 %. Here, most of the plants not run as CHP plants are biogas-powered micro gas turbines or small gas engines used to generate electricity. Looking only at solid biomass, nearly 89 % of electricity output is generated via CHP. The total heat capacity of all CHP plants (fossil and biogenic) stood at more than

9.2 GW_{th} in 2012, generating more than 30 TWh of heat (e-control, 2012a). Of this, around 21 TWh was sold to retailers or end consumers, and the rest was used in internal company systems. Developments in the thermal and electrical capacity of all fossil and biogenic CHP plants currently in operation since the year 2000 are illustrated in Figure 3-6. The figure demonstrates that the installed thermal and electrical capacity of CHP plants has been rising steadily, whereas the cumulated capacity of power plants not using CHP has fallen.

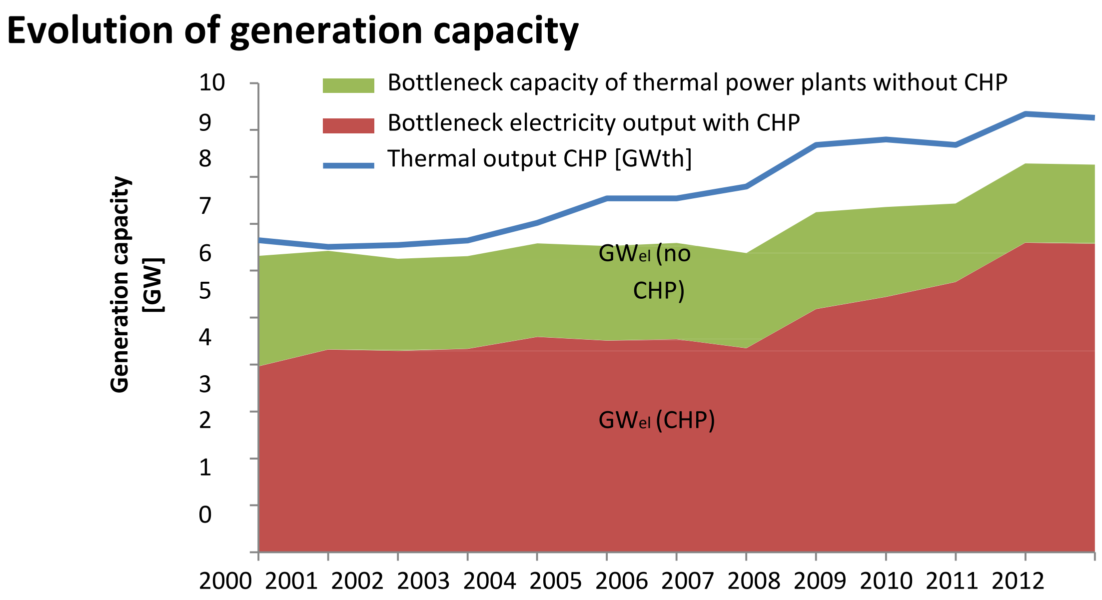


Figure 3-6: Installed capacity (electrical and thermal) of thermal power stations in Austria (source: e-control: key indicators on thermal power stations with and without CHP – annual development, e-control, 2012b)

In Austria, large fossil-fuel-powered **heating plants** are almost exclusively found in large cities. The overwhelming majority of thermal power stations are small plants powered using biogenic energy sources. According to the 2013 Biomass Heating Survey (Haneder and Furtner, 2014), a total of 1140 wood-chip-fired furnaces with a thermal output of more than 1 MW_{th} have been installed since 1980. Combined, these furnaces have a total capacity of almost 3000 MW_{th}. In almost all cases, plants of this size are used to supply local or district heating grids. If these plants are assumed to have an average lifetime of roughly 20 years, it can be estimated that around 900 plants of this size class with a total capacity of 2600 MW_{th} are currently installed.

As regards **waste** disposal, there are 32 incineration and co-incineration plants with a capacity of over 2 t/h in Austria. Of these, 15 are industrial plants, 8 belong to energy providers and 9 are attributable to special municipal or recycling companies

(Grech and Stoiber, 2014). The mapping of these plants along with biomass thermal power stations and biomass CHP plants as illustrated in Figure 3-7 shows that these are often located in close proximity to existing district heating grids. Plants belonging to municipalities and energy providers in particular already make a substantial contribution to supplying district heating grids. Industrial co-incineration plants are usually used to generate heat for particular internal processes. In addition, there are 33 incineration and co-incineration plants with capacities of below 2 t/h that are not discussed in detail here (Grech and Stoiber, 2014).

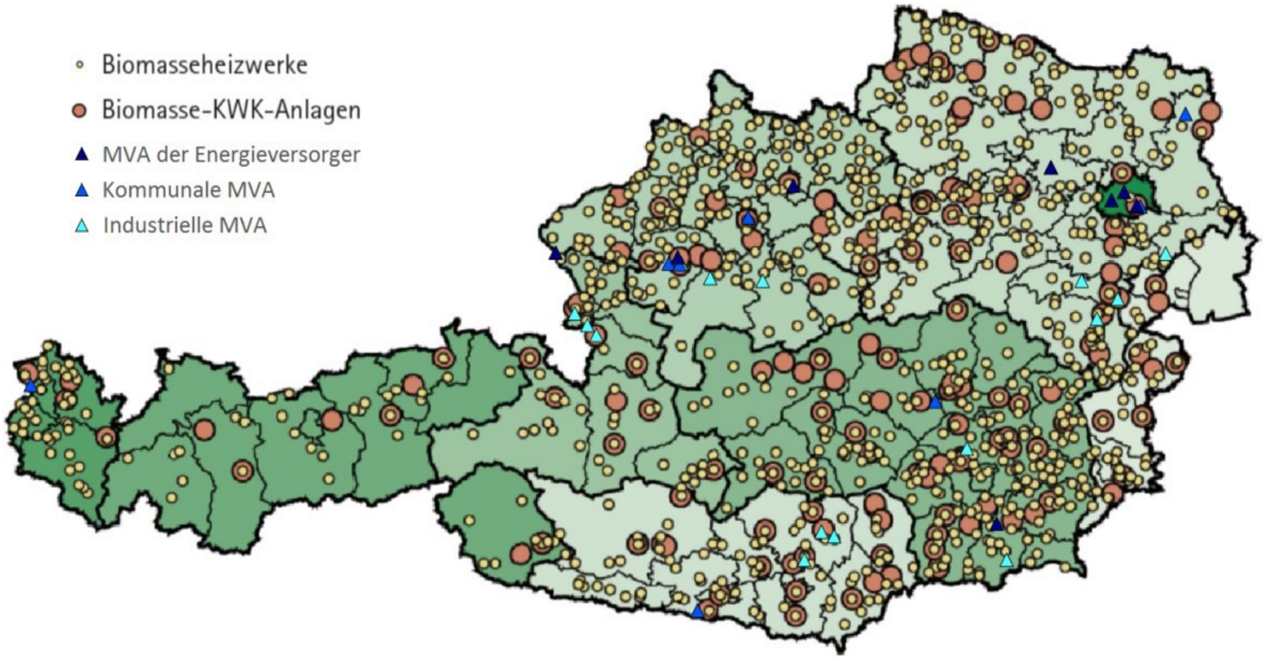


Figure 3-7: Biomass thermal power stations, biomass CHP plants and waste incineration plants with capacities of over 2 t/h in Austria (source: 2013 base map of biomass thermal power stations and biomass CHP plants of the Lower Austrian Chamber of Agriculture and data of the MVA from the report of the BMLUFW on incineration and co-incineration plants in line with Section 18 of the Austrian Waste List Regulation)

Biomasseheizwerke	Biomass thermal power plants
Biomasse-KWK-Anlagen	Biomass CHP plants
MVA der Energieversorger	Waste incineration plants owned by energy providers
Kommunale MVA	Municipal waste incineration plants
Industrielle MVA	Industrial waste incineration plants

Industrial **waste heat** in economically exploitable quantities is primarily produced by energy-intensive industry. If the temperature level remains high enough after internal use of the heat, and if there is sufficient heat flow, it is advisable to use this cheap energy to supply nearby district heating grids.

A number of large industrial plants already supply district heating grids with their waste heat today. This enables larger grids in particular to cover some of their basic load, as many of the processes continually produce heat. Below are some examples of waste heat being supplied to district heating grids:

- The CHP of OMV Schwechat supplies the Viennese district heating grid.
- Hrachowina and Henkel Austria supply the district heating grid in Vienna.
- The Marienhütte steelworks supplies the district heating grid in Graz.

- Böhler Edelstahl supplies the Kapfenberg district heating grid.
- Voestalpine Stahl Donawitz supplies the Leoben district heating grid.
- The Hofmann Kirchdorf cement works supplies the district heating grid of EnergieAG in Kirchdorf.
- The Schweighofer Hallein paper factory supplies the Salzburg district heating grid.

Geothermal energy is currently used in 15 plants in Austria in order to supply district heating. Total installed heat capacity stands at around 93 MW, generating thermal output of around 139 GWh/a. Figure 3-8 indicates existing plants and potential areas where application of geothermal is possible in accordance with the surveys conducted as part of the Regio Energy project (Stanzer et. al, 2010).

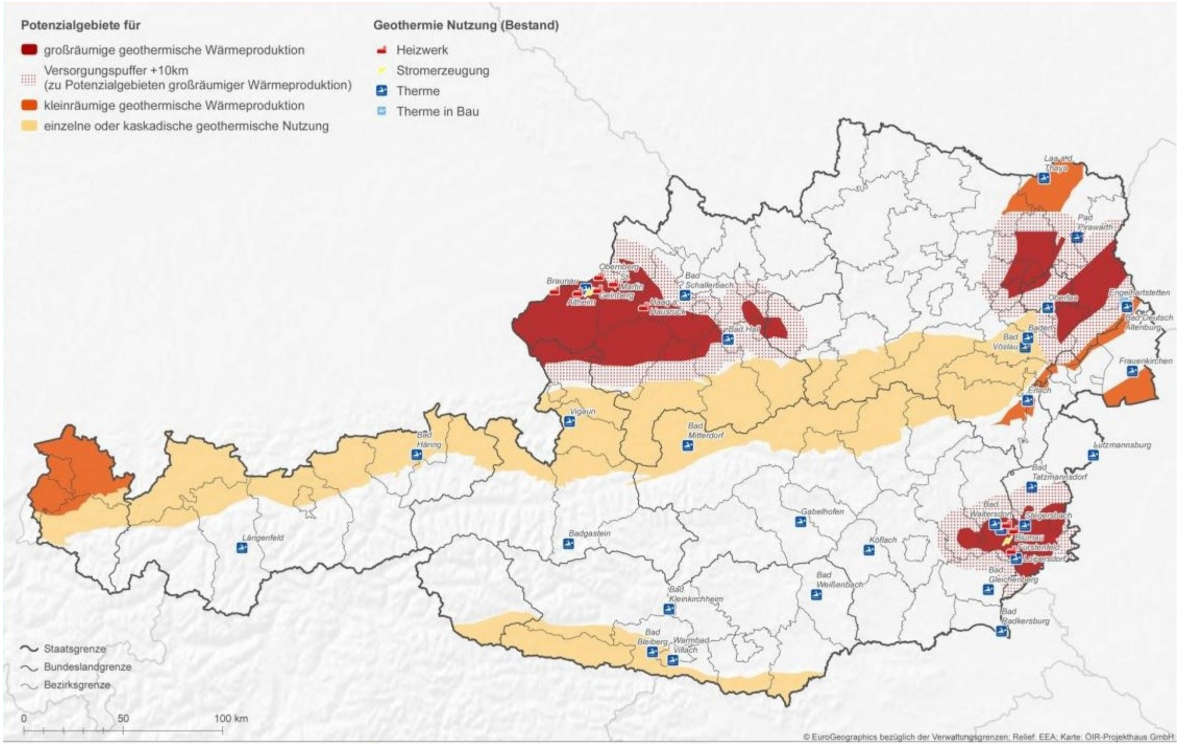


Figure 3-8: Existing and potential hydrothermal geothermal plants in Austria (source: REGIO Energy – scenarios for renewable energy potential in the years 2012/2020, Austrian Institute for Spatial Planning, Stanzer et. al, 2010)

Potenzialgebiete für	Potential areas for
Großräumige geothermische Wärmeproduktion	large-scale geothermal heat production
Versorgungspuffer +10km (zu Potenzialgebieten großräumiger Wärmeproduktion)	supply buffer +10 km (from areas with potential for large-scale geothermal heat production)
Kleinräumige geothermische Wärmeproduktion	small-scale geothermal heat production
Einzeine oder kaskadische geothermische Nutzung	individual or cascading geothermal use
Geothermie Nutzung (Bestand)	Geothermal usage (existing)
Heizwerk	Thermal power plant
Stromerzeugung	Electricity generation
Therme	Thermal springs
Therme in Bau	Thermal springs under construction
Staatsgrenze	National border
Bundeslandgrenze	Federal state border
Bezirksgrenze	District border

Large-scale **solar thermal** plants provide an opportunity to use solar energy in order to produce heat for district heating grids. Due to the high levels of heat production in the summer months, they are particularly suitable for grids with no access to low-cost forms of heat in the summer (e.g. through waste incineration or waste heat usage). At the end of 2010, around 4.5 million square metres of thermal solar panels were in operation in Austria, which equates to an installed capacity of 3191 MW_{th}**.** The average annual market growth rate in Austria between 2000 and 2010 stood at 7 %. During this period, the annual installed capacity nearly doubled, rising from 117 MW_{th} to 200 MW_{th}. However, almost all of the installed capacity is used by small-scale private users to generate hot water for their own use. Over the past few years, though, an increasing number of large-scale solar facilities have been established in order to supply district heating grids. At the current time, several large thermal solar energy systems are connected to urban district heating systems in Austria. The largest of these systems are listed in Table 3-1.

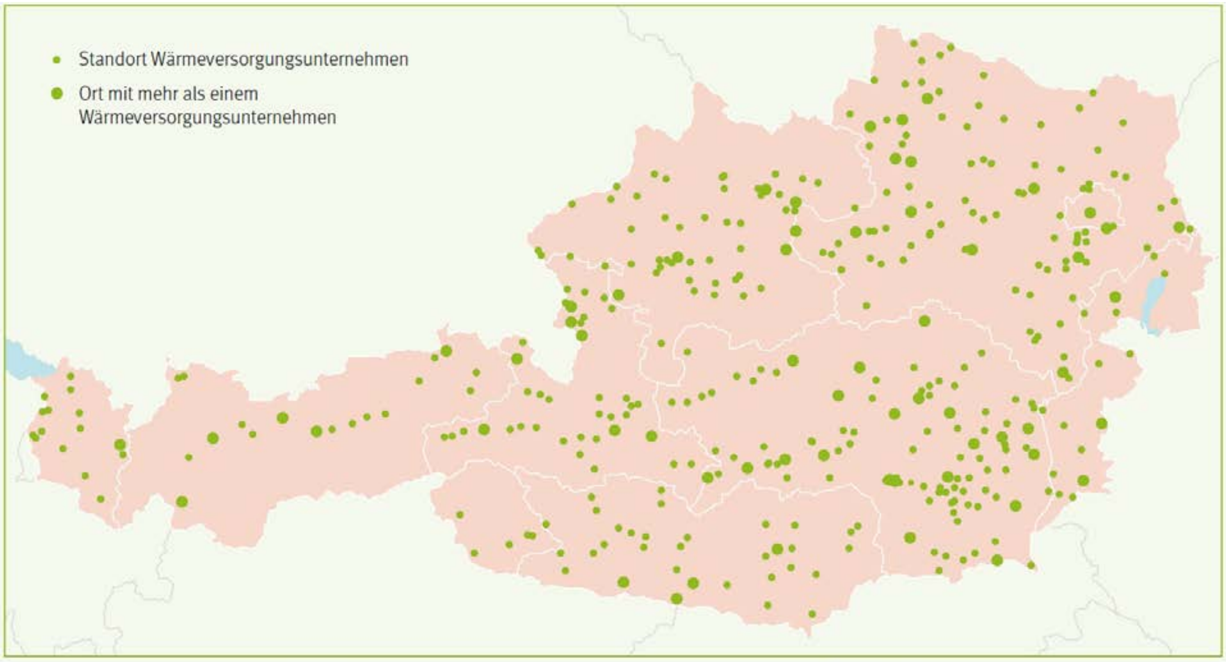
Table 3-1: Large-scale solar energy systems in Austria (source: solar-district-heating.eu)

System	Year	Operator	Location	Surface area	Capacity [kW_{th}]
District heating	2006	solar.nahwaerme.at, AT	Graz	4960	3472
Andritz Waterworks	2009	solar.nahwaerme.at, AT	Graz	3860	2702
Wels	2011	Wels Fernwärme, AT	Wels	3388	2400
Berliner Ring	2004	solar.nahwaerme.at, AT	Graz	2480	1736
Eibiswald	1997	Nahwärmegen. Eibiswald, AT	Eibiswald	2,450	1,715
Salzburg	2011	Lehen Public Utility Company	Salzburg	2150	1505
UPC Arena	2002	nahwaerme.at, AT	Graz	1407	985
Leoben	2013	Göss Brewery	Leoben	1375	963
Gleinstätten	2006	Nahwärme Gleinstätten GmbH, AT	Gleinstätten	1315	921
Bilderland	1979	Bilderland GmbH, AT	Bilderland	1284	899
Bad Mitterndorf	1997	Genossensch. Biosolar BM, AT	Bad Mitterndorf	1120	784
Innsbruck	1999	Wohnen am Lohbach I, AT	Innsbruck	1080	756
Sieghartskirchen	2013	Fleischwaren Berger G.m.b.H.	Sieghartskirchen	1068	748
Bolaring	2000	Gem. Salzb. Wohn. G.m.b.H., AT	Salzburg	1056	739
Innsbruck	2009	Lodenareal, AT	Innsbruck	1050	735

3.2.3 Structure of district heating grids

In Austria, there are over 600 district heating companies, ranging from large municipal suppliers to small, regionally active companies. Many of the smaller companies operate only one **district heating grid**, whereas the larger providers often operate a number of grids in different municipalities. Figure 3-9 shows sites where one or several heating providers are based according to the Industry Association for Gas and Heating.

The largest Austrian provider is Wien Energie GmbH; while it only operates one grid, this grid is by far the biggest in the country. Further large providers include EVN Wärme AG, which operates 63 biomass plants in Lower Austria; Energie AG Wärme, which operates 6 district heating grids in Upper Austria; Salzburg AG which operates a further 9 grids in addition to the Salzburg Hallein district heating grid; Steirische Gas Wärme, which is active within 24 heating grids; Kelag Wärme, which operates around 80 district heating grids with over 1000 heating plants; and then Klagenfurt Public Utilities, St. Pölten Public Utilities, Leoben Public Utilities and Wels Public Utilities, each supplying their own city with district heating. In smaller cities and towns, customers are supplied with heat by a host of small grid operators who mostly use biomass plants.



Übersichtskarte: Wärmeversorgungsunternehmen in Österreich

Standort Wärmeversorgungsunternehmen	Location of a heating company
Ort mit mehr als einem Wärmeversorgungsunternehmen	Location with more than one heating company
Übersichtskarte: Wärmeversorgungsunternehmen in Österreich	Overview map: heating companies in Austria

Figure 3-9: Map of heating providers in Austria (source: Information Leaflet of the Industry Association for Gas and Heating Companies, 2013)

Up until 2001, the Industry Association for Gas and Heating Companies collected key data on the various providers. Aggregated information on the individual companies has since ceased being made available. On behalf of the State Energy Association, the consultancy 'Kommunalkredit Public Consulting' manages a database containing technical and economic data on projects funded under the Klima:aktiv programme 'qm heizwerke'. To qualify for funding, a biomass-fuelled heat generator must have a total rated output of at least 400 kW, and must have a line length including building connection lines of at least 1000 lfm. The qm heizwerke quality management system also collects data on CHP plants that meet the aforementioned conditions.

On the basis of an analysis of the rated outputs and sales volumes of 169 biomass grids from this database and subsequent allocation and extrapolation to over 600 rated outputs, it was possible to estimate the number of grids in the various size classes, their contractual rated output, average full-load hours and thereby the volume of energy supplied. If these 600 grids are regarded as representative of the roughly 1200 existing grids, biomass grids with rated outputs of up to 25 MW are more or less evenly distributed across the size classes. This means that approximately 14 % to 18 % of the grids fall under each of the six classes. As such, fewer than 4 % of biomass grids have a rated output of over 25 MW, and far fewer than 1 % have an output of over 50 MW. Yet the volume of energy sold increases sharply with rising rated output: 80 % of grids are situated in the 'up to 7 MW rated output' class, but are responsible for only 1/3 of the heat supplied. A further third is supplied via grids with a rated output of 7 to 25 MW, and the remaining third via grids with a rated output of over 25 MW.

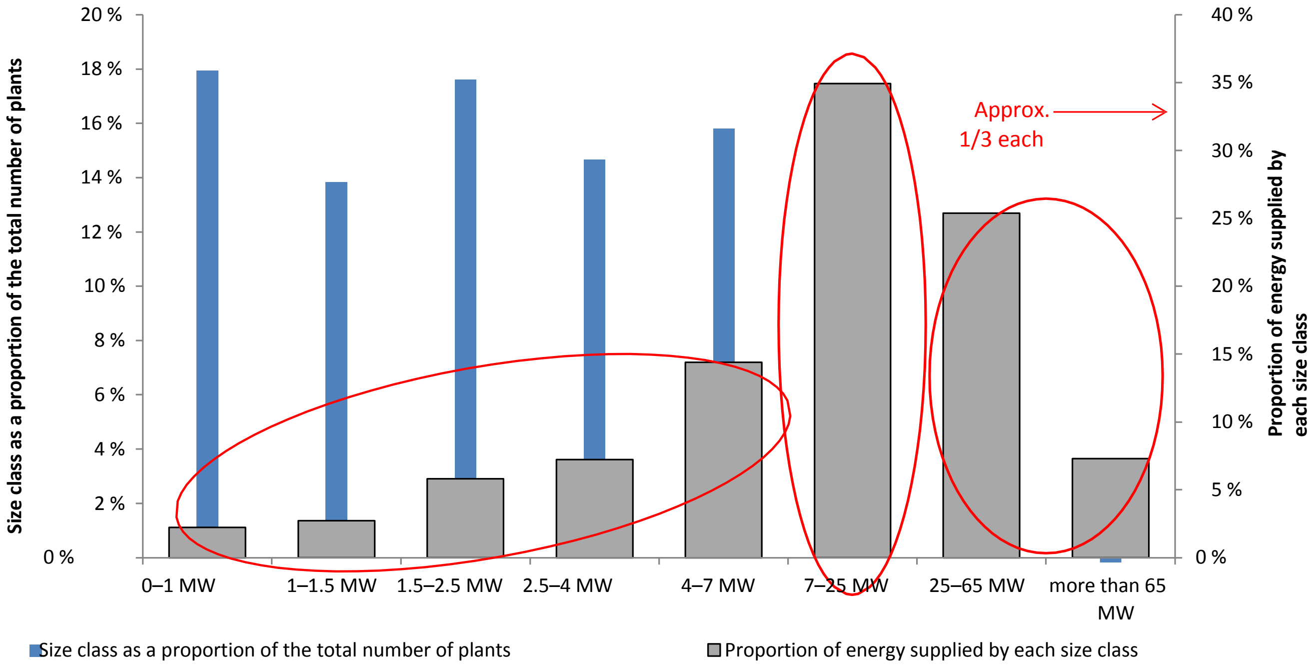


Figure 3-10: Breakdown of biomass grids by size class and proportional energy volumes (source: analysis of the quality management data of the LEV)

A further analysis of the QM database was conducted taking into account several different parameters. On the basis of a dataset of 122 biomass local heating grids on which all the necessary data was available, the grids were divided into the following three categories:

- **Cluster I, primarily bulk consumers:**

more than 75 % of the heat sold goes to customers with a heating consumption volume of over 150,000 kWh/a.

- **Cluster II, mixed grid structure:**

less than or equal to 75 % of the heat sold goes to customers consuming more than 150,000 kWh/a AND less than or a maximum of 25 % of the heat sold goes to customers consuming less than 50,000 kWh/a.

- **Cluster III, primarily small-scale consumers:**

less than 75 % of the heat sold goes to customers consuming more than 150,000 kWh/a AND more than 25 % of the heat sold goes to customers consuming less than 50,000 kWh/a.

For these networks, data on the following parameters was collected and then analysed to find mean and median values and outliers:

- number of heating grids per cluster
- number of consumers (= heat customers)
- total line length
- technical rated output for all heat customers
- network loss capacity
- energy supply: generated heat (= fed into the grid)
- heat distribution, annual sales

- network losses as a percentage of supplied heat
- heat density
- number of boilers, their capacities and energy source used per heating grid.

21 % of the heating grids analysed could be allocated to Cluster I and 44 % to Cluster II, with the remaining 34 % demonstrating a customer structure featuring mostly small-scale consumers. Looking at the number of heat customers within each cluster, this figure decreases for the grids with mainly bulk consumers, as is to be expected. Proportionally, the majority of customers in the grids analysed are not, however, part of structures used primarily by small-scale consumers, but are part of grids with a mixed structure. On the other hand, the technical parameters line length, rated output and heat distribution increase for networks with primarily bulk consumers, which gives rise to economic advantages. For example, 40 % of annual energy sales are attributable to Cluster I, despite this cluster accounting for only 18 % of consumers, whereas only 14 % of the heating volume is attributable to grids with primarily small-scale consumers, despite this cluster accounting for over 34 % of connected customers. Figure 3-11 illustrates how these parameters stand in relation to one another for each of the grid types.

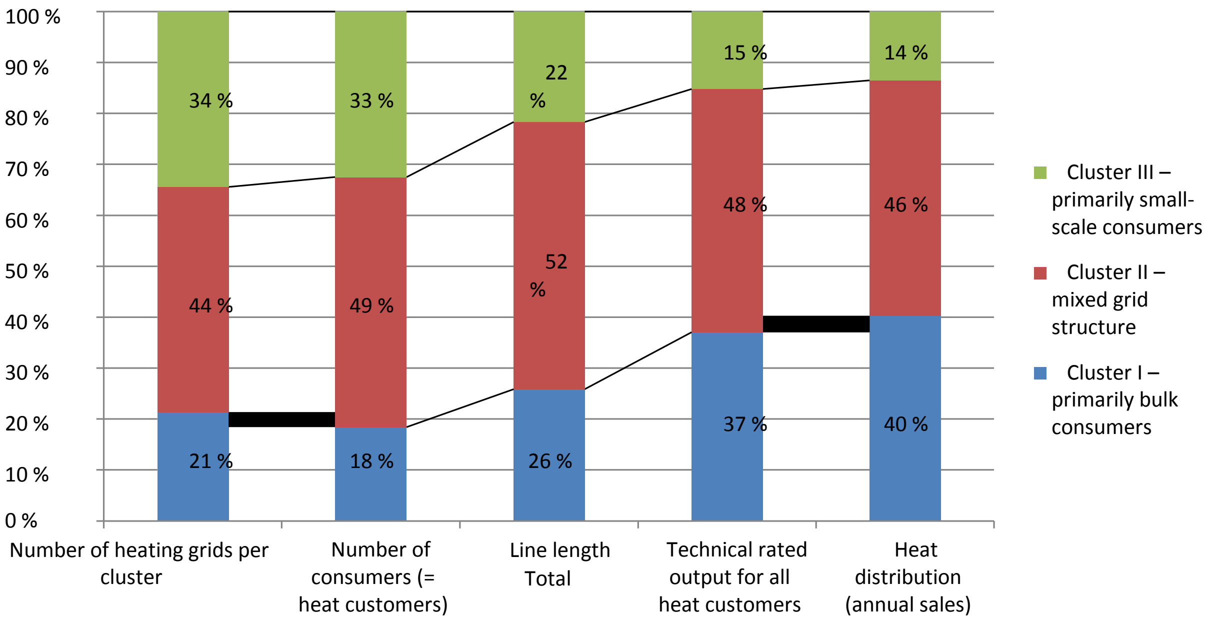


Figure 3-11: Comparison of the technical parameters for the three grid clusters identified (source: analysis of the quality management data of the LEV)

In Figures 3-12 to 3-14, the minimum and maximum values, the median and mean values, the total volume for the three clusters and the sum of the 122 grids analysed are presented and interpreted for selected technical parameters.

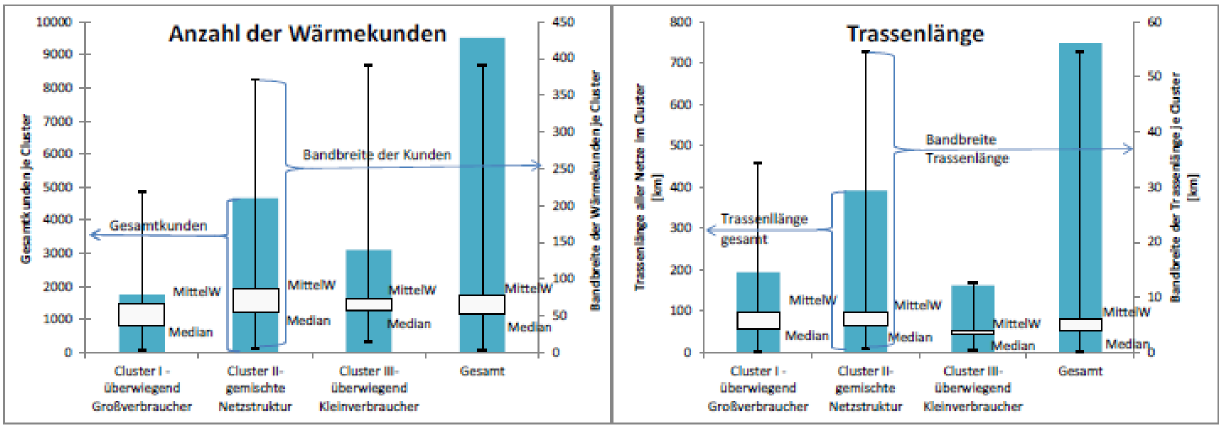


Figure 3-12: Number of heating customers and line lengths of the grid clusters (source: analysis of the quality management data of the LEV)

Anzahl der Wärmekunden	Number of heating customers
Gesamtkunden je Cluster	Total number of customers per cluster
Gesamtkunden	Total number of customers
MittelW	Mean
Median	Median
Bandbreite der Kunden	Range of customers
Cluster I – überwiegend Großverbraucher	Cluster I – primarily bulk consumers
Cluster II – gemischte Netzstruktur	Cluster II – mixed grid structure
Cluster III – überwiegend Kleinverbraucher	Cluster III – primarily small-scale consumers
Gesamt	Total
Bandbreite der Wärmekunden je Cluster	Range of heating customers per cluster
Trassenlänge	Line length
Trassenlänge aller Netze im Cluster [km]	Line length for all grids in the cluster [km]
Trassenlänge gesamt	Total line length
Bandbreite Trassenlänge	Line length range
Bandbreite der Trassenlänge je Cluster	Line length range per cluster

Looking at the variation in the parameters within each grid, it is clear that the dispersion of both the number of customers and line length is very high in all three clusters, and is situated within a similar range. In the case of the number of customers, this ranges in all clusters from a couple of consumers to a couple of hundred; as for line length, this ranges from a couple of hundred metres to several kilometres. In the case of grids with primarily small-scale consumers, it can be derived from the similarity between the median value and the mean value that the grids are more evenly dispersed across the entire range than in the case of grids with primarily bulk consumers. If the median deviates substantially from the mean, this means that some of the grids were outliers. Small-scale consumer grids are therefore far more homogeneous in terms of their parameters than bulk consumer grids, and are therefore easier to classify.

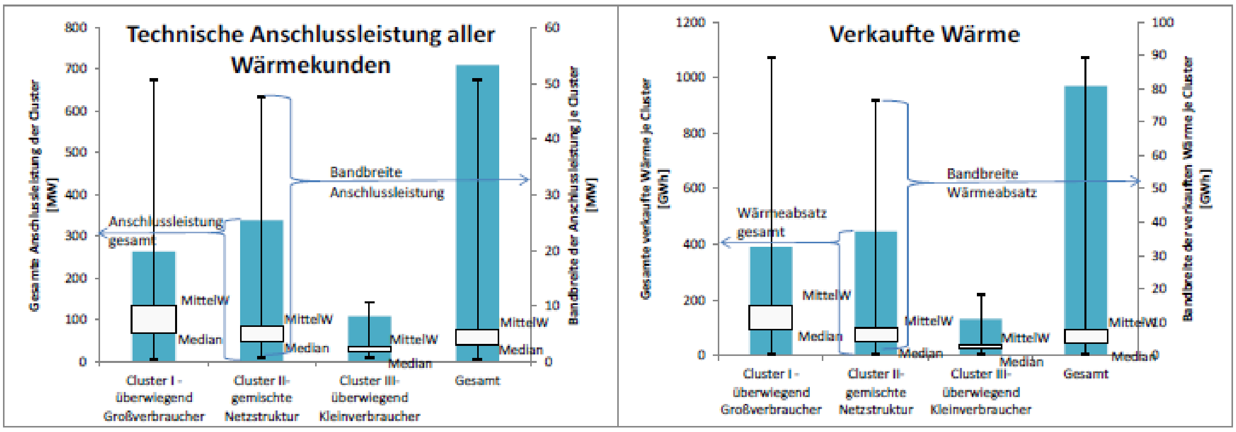


Figure 3-13: Technical rated output and volume of heat sold for each of the grid clusters (source: analysis of the quality management data of the LEV)

Technische Anschlussleistung aller Wärmekunden	Technical rated output for all heat customers
Gesamte Anschlussleistung der Cluster [MW]	Total rated output for the cluster [MW]
Anschlussleistung gesamt	Total rated output
Bandbreite Anschlussleistung	Range of rated outputs
MittelW	Mean
Median	Median
Cluster I – überwiegend Großverbraucher	Cluster I – primarily bulk consumers
Cluster II – gemischte Netzstruktur	Cluster II – mixed grid structure
Cluster III – überwiegend Kleinverbraucher	Cluster III – primarily small-scale consumers
Gesamt	Total
Bandbreite der Anschlussleistung je Cluster [MW]	Range of rated outputs per cluster [MW]
Verkaufte Wärme	Heat sold
Gesamte Verkaufte Wärme je Cluster [GWh]	Total quantity of heat sold per cluster [GWh]
Wärmeabsatz gesamt	Total heat distribution
Bandbreite Wärmeabsatz	Range of heat distribution
Bandbreite der verkauften Wärme je Cluster [GWh]	Range of heat quantities sold per cluster [GWh]

As expected, technical rated output increases significantly as the proportion of bulk consumers rises. In the case of many small-scale consumers, however, the range of output values is much smaller and more evenly dispersed.

Although the average line length per customer for grids primarily used by small-scale consumers is only half that of grids primarily used by bulk consumers, heat density (i.e. the volume of heat sold per metre of line) is more than twice as high in grids primarily used by bulk consumers than in grids used by small-scale consumers. On the basis of these values, it is possible to derive the conditions that should be met in order to ensure cost-effective operation of grids.

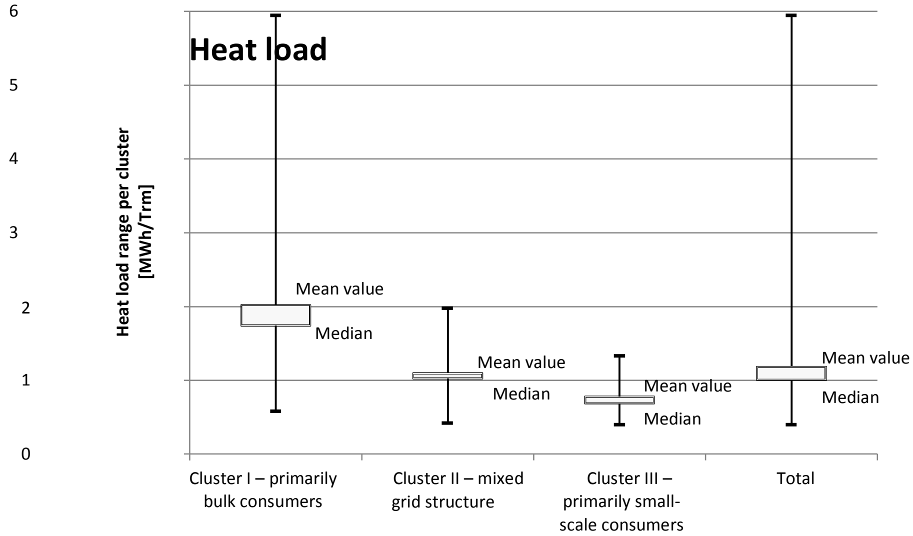


Figure 3-14: Heat density ranges for each grid cluster (source: analysis of the quality management data of the LEV)

As regards the types of heat generators installed in the 122 biomass grids analysed, 98 % of the grids have a biomass boiler, and 8 % even have a biomass CHP facility. 55 % of the grids have an oil- or gas-powered peak load boiler, and a full 29 % of grids obtain some of their heat from heat recovery systems (HRS). Other generation technologies such as external boilers, waste heat from industry or biogas facilities can be found in 10 % of the grids. Installed heat capacity and the volume of heat generated using each of the technologies are illustrated in Figure 3-15. Biomass boilers account for 41 % of total installed capacity, and generate 66 % of the total volume of heat. Although oil/gas boilers account for 40 % of installed capacity, they only provide 1 % of the volume of heat generated, which suggests that they are being used as an outage reserve or as peak load boilers, and operate for only short periods each year.

Typically, the biomass boilers have a capacity of between 0.5 MW and 10 MW, with 50 % of boilers exhibiting a capacity of up to 1.6 MW. Typical oil-/gas-fired boilers have an installed capacity of between 0.5 MW and 25 MW, with 50 % exhibiting a capacity of less than 3 MW.

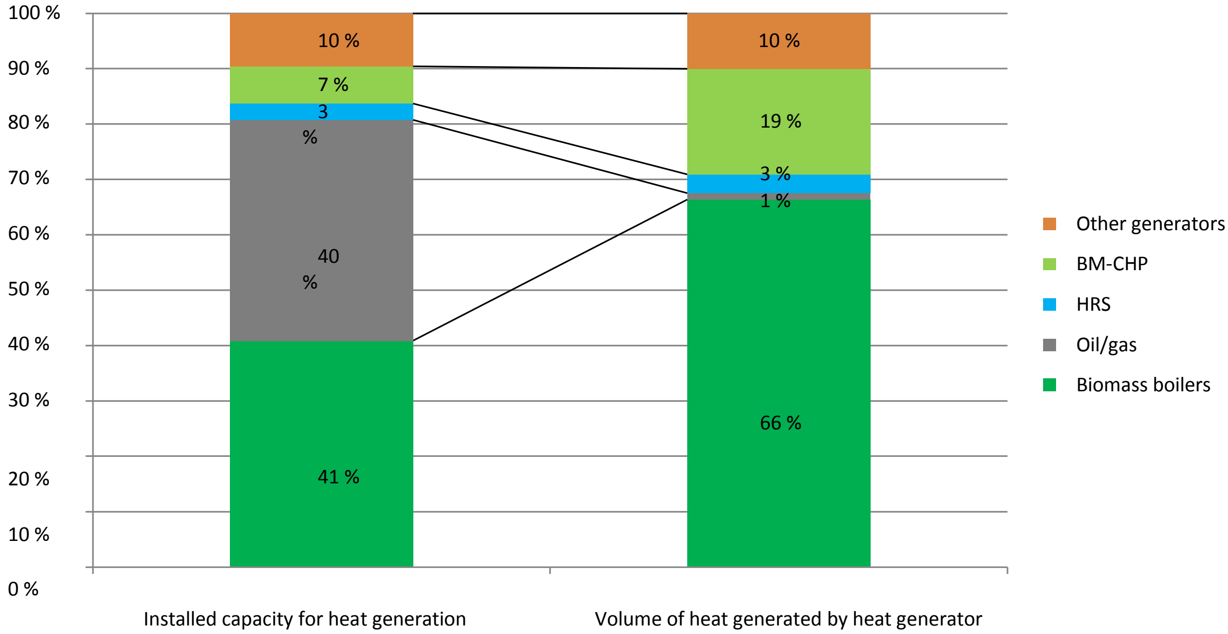


Figure 3-15: Proportion of capacity and heat volume accounted for by the various heat generators (source: analysis of the quality management data of the LEV)

It is possible to get an idea of the prevailing inlet temperatures in district heating grids by analysing the grid temperatures found in the characteristic data collected by district heating companies. Figure 3-16 shows inlet and return flow temperatures in winter for 60 individual grids. These grids have been sorted in descending order by distribution volume. This serves to demonstrate that smaller grids tend to have lower inlet temperatures. This may either be due to the fact that smaller grids are newer than larger ones, so they attempt to keep the inlet temperature as low as possible, or to the fact that grids that have reached their capacity limits attempt to increase the heat output transferred by increasing the inlet temperature.

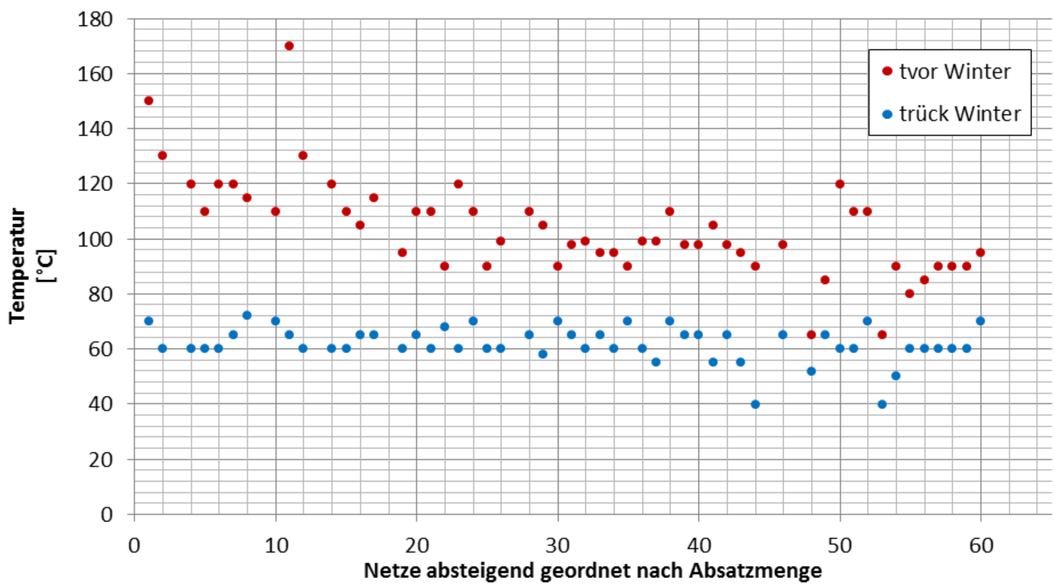


Figure 3-16: Inlet and return flow temperatures in winter for 60 grids, sorted in descending order according to distribution volume (source: characteristic data from heat providers, FGW 2001)

Tvor Winter	Winter inlet temperature
Trück Winter	Winter return flow temperature
Temperatur (°C)	Temperature (°C)
Netze absteigend geordnet nach Absatzmenge	Grids in descending order according to distribution volume

3.2.4 Assumptions relating to developments in existing facilities up until 2025

When determining economic potential, a distinction is made between existing facilities and new investments. In each of the primary regions evaluated (see 4.2.1), the existing power plant fleet is assessed on the basis of the year of construction and the average technical lifetimes of the plants according to fuel usage. The assumed lifetimes can be found in Table 3-2.

Table 3-2: Assumed lifetimes of power plants

Technology	Assumed lifetime in years
Gas incl. CHP	30
Coal incl. CHP	40
Biomass incl. CHP	30
Oil-fired thermal power stations	40

If a plant will have reached the end of its technical lifetime by 2025, it is assumed that it will have been decommissioned. By way of example, Figure 3-17 indicates the proportion of decommissioned power stations based on an assumed average lifetime of 35 years. For larger plants (>5 MW), decommissioning times are estimated on the basis of power plant data collected. The number of facilities in operation in 2025 can thereby be allocated to the individual primary regions and taken into account when determining economic potential.

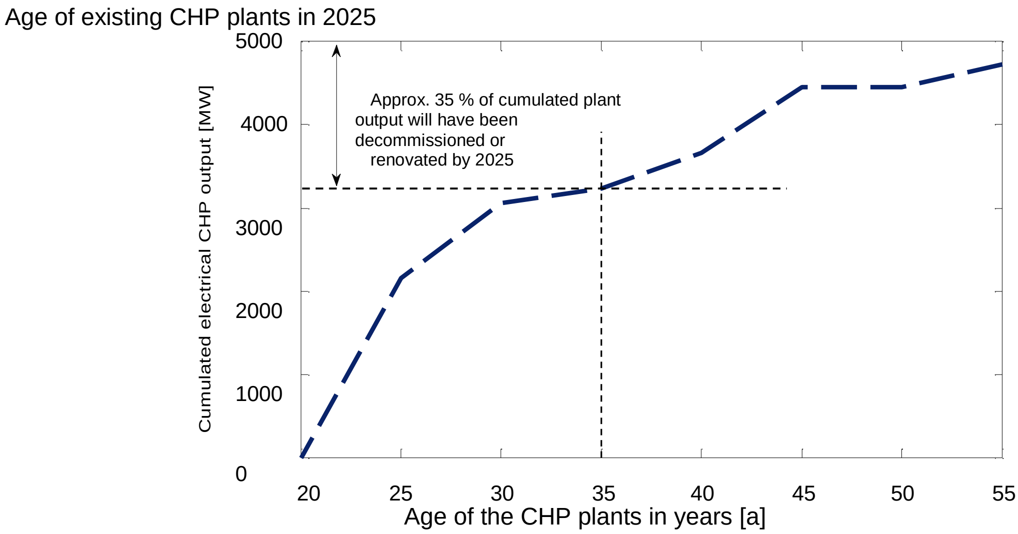


Figure 3-17: Developments in the decommissioning of power plants by 2025

For waste incineration plants, it is assumed that these will still remain in operation until 2025 or will be modernised, even if they have already exceeded their technical lifetime. The investment costs thereby incurred are not taken into account in the cost-effectiveness calculation, since the primary function of these plants is to process waste, not necessarily to produce heat.

Furthermore, it is assumed that all heating grids existing today will still be in operation in 2025. This also reduces the costs incurred as a result of providing district heating in areas of the regions identified as 'primary regions' already connected to a grid.

4 Technical potential for district heating, cogeneration and efficient heating and cooling

This section aims to determine the technically feasible potential for covering demand through high-efficiency cogeneration, micro-CHP and efficient district heating and cooling.

In order to do so, 'high-efficiency cogeneration' and 'efficient district heating and cooling' are first defined (Section 4.1). Subsequently, the methodology for determining regional system limits and for distinguishing potential primary and secondary district heating regions is explained (Section 4.2). The technical potential for district heating and cogeneration is then determined in Sections 4.3 and 4.4. Sections 4.5 to 4.9 look at the technical potential of individual energy sources and technologies (industrial waste heat, biomass, geothermal energy and ambient heat, waste incineration, solar thermal energy). Finally, Section 4.10 provides an overview of technical potential for district cooling.

When calculating technical potential, the focus is on technical rather than economic feasibility, although this distinction is not always entirely clear. The technical potential calculated here provides the basis for the calculation of economic potential in Section 5.

Later on in this section, there is also a description of the centralised (i.e. grid-bound) and decentralised (i.e. building-related) technologies that should be considered, and the parameters for these technologies that are relevant to the calculations. The technologies included in the cost-benefit analysis in Section 6, the technical potential of which is analysed in a previous step, are described in Section 6.2. Each of these technologies is able to service one or more of the three possible temperature levels: a) cooling, b) combined space heating and hot water and c) high-temperature heat for industry.

As regards the number of technologies analysed, a balance has been struck between technical detail and clarity. A total of 24 heating and cooling technologies have been selected, 21 of which are used to supply heat, and 3 of which are used for cooling.

For each of these technologies, examples in the context of the situation in Austria were used to determine the characteristics of the technologies for the purpose of the cost-benefit analysis and the potential calculation.

4.1 Definition of efficient district heating and cooling and of high-efficiency cogeneration

According to Annex II of the Energy Efficiency Directive (Directive 2012/27/EU), the term 'high-efficiency cogeneration' refers to:

- cogeneration production from cogeneration units providing primary energy savings (PES) of at least 10 % compared with the references for separate production of heat and electricity, calculated on the basis of the following formula;

$$PES = \left(1 - \frac{1}{\frac{\eta_W}{\eta_{refW}} + \frac{\eta_E}{\eta_{refE}}}\right)100$$

Equation 4-1

- production from small-scale and micro-cogeneration units providing primary energy savings may qualify as high-efficiency cogeneration.

The efficiency reference value for electricity generation using gas for plants constructed between 2006 and 2011 stands at 53.1 %. This baseline efficiency value was increased by 0.6 percentage points from 52.5 % due to a lower average annual temperature of 9°C instead of 15°C. For heat generation from gas boilers, an efficiency reference value of 90 % is stipulated (Implementing Decision 2001/877/EU).

'Efficient district heating and cooling' means a district heating or cooling system using at least 50 % renewable energy, 50 % waste heat, 75 % cogenerated heat or 50 % of a combination of such energy and heat.

'Efficient individual heat and cooling' means an individual heat and cooling supply option that, compared to efficient district heating and cooling, measurably reduces the input of non-renewable primary energy needed to supply one unit of delivered energy within a relevant system boundary or requires the same input of non-renewable primary energy but at a lower cost, taking into account the energy required for extraction, conversion, transport and distribution.

4.2 Methodology for dividing potential district heating regions into primary and secondary regions

The EU Energy Efficiency Directive (Directive 2012/27/EU) stipulates that, when analysing the potential for high-efficiency cogeneration and efficient district heating, the areas considered must have a plot ratio of greater than 0.3. Despite the building density correction made as described in Section 2.1.1, the application of this plot ratio across Austria leads to the identification of only 20 regions with an energy volume of more than 1 GWh that meet the plot ratio criterion.

Therefore, in order to increase the range of regions available, an extended method was used to identify the potential district heating areas to be analysed. The extended method described below gives rise to 38 regions being identified, referred to here as 'primary district heating regions'. For all municipalities that do not fall under these primary regions, a correlation of heat demand and available potential for renewable energy and efficiency technologies is performed by grouping regions with similar characteristics to form a typology of 30 regions in Austria referred to here as 'secondary regions'.

4.2.1 Primary district heating regions

In order to select particular regions for further analysis, a focal function was applied to determine the spatial distribution of and the relations between various neighbouring heat demand regions. To do so, heat demand spots for various heat density limits were combined to form district heating regions upon a minimum demand threshold being exceeded. This approach takes into account the fact that an increase in the consumption of heat for space heating and hot water within the zones allows increasingly large distances to be bridged between various heat demand zones. It was assumed that municipality borders in principle form a barrier to the linking up of heat spots to form contiguous zones; however, if the demand for heat is sufficient on both sides of the border, this barrier can be overcome. 10 GWh/km² was selected as the heat density limit value (for demand for space heating and hot water), and in line with the focal function all contiguous 250x250m grid elements belonging to the relevant region were analysed. Across Austria, there are 690 areas that meet these criteria. For these areas, the plot ratio of 0.3 stipulated by the Directive was then lowered to 0.25, and reduced by an additional amount depending on energy volumes.[6] A minimum threshold of 10 GWh/a was also specified for space heating and hot water demand in the areas that meet these criteria.

In order to illustrate the method used, Figure 4-1 shows a map section from Northern Burgenland, on which the regions potentially suitable for application of district heating (primary district heating regions) are indicated. All areas outlined in blue are contiguous areas that reach the required heat density limit in line with the focal function. In this image, Eisenstadt (outlined in dark blue) is the only area that also meets the plot ratio and energy volume criteria.

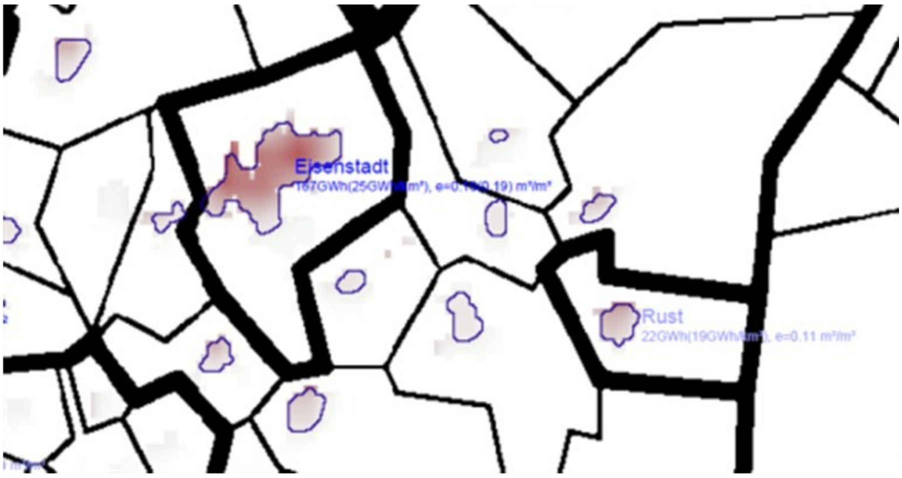
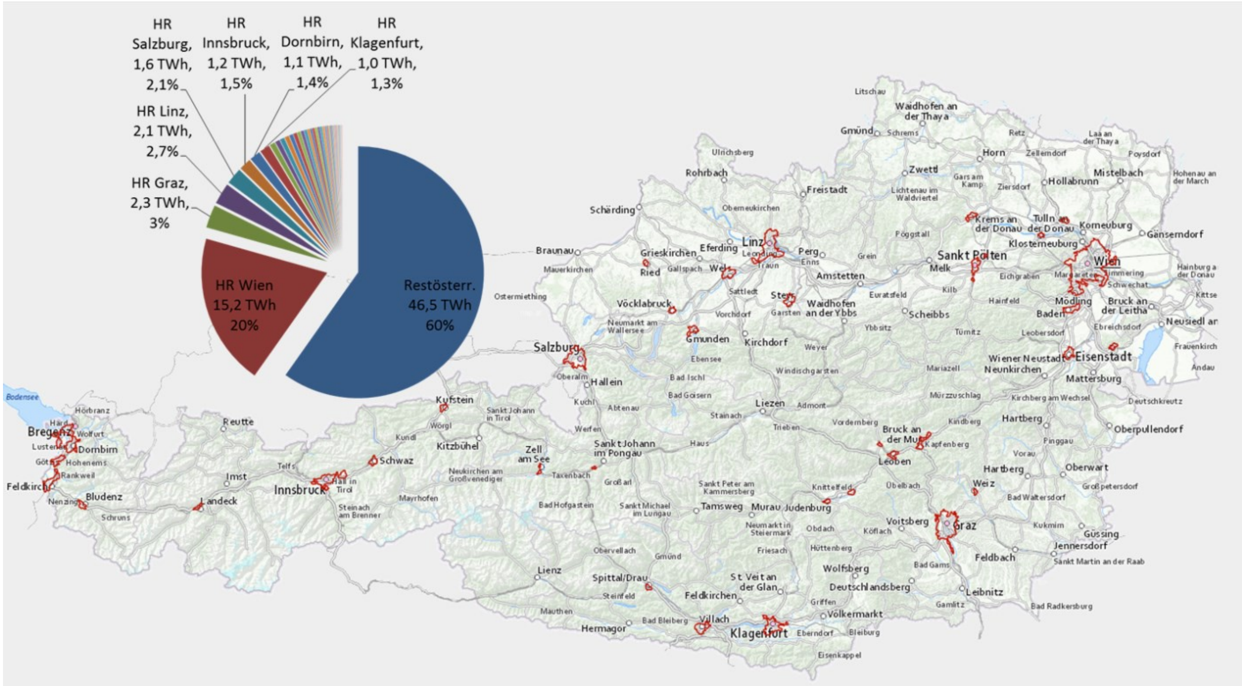


Figure 4-1: Identification of regions potentially suitable for application of district heating using the focal function in Invert/EE-Lab

Eisenstadt	Eisenstadt
Rust	Rust

[6] In line with this method, areas in which a large volume of energy could be distributed must only achieve a plot ratio of 0.1.

Using this method, 38 of the areas defined as 'primary district heating regions' were subjected to a detailed individual analysis. In total, 109 municipalities are encompassed by these primary district heating regions, which are named after the municipality with the greatest heat demand for space heating and hot water. The primary regions as well as their space heating and hot water demand are illustrated in Figure 4-2 and listed in full in Table 4-1. The combined heat demand of all of the primary regions stands at 34.4 TWh, i.e. roughly 40 % of total heat demand in Austria in 2025 according to the BAU scenario (see Section 2.2.2). Half of the energy demand in the primary regions is accounted for by the Vienna region, including the accompanying surrounding municipalities.



HR Salzburg	Salzburg primary region
HR Innsbruck	Innsbruck primary region
HR Dornbirn	Dornbirn primary region
HR Klagenfurt	Klagenfurt primary region
HR Linz	Linz primary region
HR Graz	Graz primary region
HR Wien	Vienna primary region
Restösterr.	Rest of Austria

Figure 4-2: Primary district heating regions and their space heating and hot water demand, also as a proportion of total demand in Austria in the BAU scenario for 2025. See: http://www.austrian-heatmap.gv.at

Table 4-1: List of the 38 primary district heating regions

No.	Name	Area [km²]	2012 heat demand [GWh]	2025 heat demand BAU scenario [GWh]
1	Vienna	289	16,645	15,255
2	Graz	112	2829	2305
3	Linz	83	2484	2128
4	Salzburg	62	1945	1645
5	Innsbruck	37	1376	1206
6	Dornbirn	43	1249	1094
7	Klagenfurt	47	1165	1007
8	Wels	21	515	437
9	Villach	26	649	554
10	Feldkirch	25	543	465
11	Wiener Neustadt	18	409	358
12	Baden	18	421	378
13	St. Pölten	25	544	451
14	Steyr	17	380	335
15	Lustenau	12	265	243
16	Kufstein	6	233	194
17	Kapfenberg	15	354	296
18	Hall in Tirol	9	235	212
19	Krems an der Donau	10	263	230
20	Hohenems	14	296	264
21	Schwaz	8	252	211
22	Knittelfeld	6	166	143
23	Gmunden	12	341	286
24	Bludenz	8	232	209
25	Ried im Innkreis	5	128	109
26	Weiz	3	93	81
27	Zell am See	4	121	108
28	Landeck	5	135	118
29	Stockerau	6	143	115
30	Tulln an der Donau	5	150	130
31	Eisenstadt	7	165	139
32	Spittal an der Drau	6	179	148
33	Trofaiach	3	60	51
34	Leoben	11	231	190
35	Matrei am Brenner	0.1	10	9
36	Judenburg	4	101	87
37	Schwarzach im Pongau	2	59	51
38	Vöcklabruck	6	145	122

4.2.2 Secondary regions

The remaining municipalities that do not meet the criteria for classification as primary regions are divided into secondary region types. These regions are examined in an aggregated manner, and the average values for the municipalities falling under each type class are used in the calculations. In cases where only a part of a particular municipality belongs to a primary region, the remaining heat demand is considered as stemming from a separate region, and is included in the typology in the same way as all other municipalities. In the case of Figure 4-1, this means that the section of Eisenstadt that does not belong to the primary region is included in the categorisation as a secondary region. For the purposes of creating the typology, the parameters regarded as most important to the economic analysis were taken into account, and all remaining municipalities were classified according to these parameters, namely: (1) climate conditions, (2) heat density, (3) proportion of existing heating grid supply volume, (4) availability of technologies/energy sources (gas, geothermal, industrial waste heat). These parameters are described in more detail below:

- The first relevant parameter identified was **climate conditions**, which has an impact on the full-load hours for district heating technologies, and height above sea level was selected as the classification parameter. Municipalities at over 1000 metres above sea level were grouped into a cluster and assigned a typical heat demand profile for a municipality located at this height. All municipalities situated at below 1000 metres above sea level were assigned a heat demand profile corresponding to the average climate conditions in Austria.

- **Heat density** has a major influence on the development and cost-effectiveness of district heating grids. Therefore, distribution of demand for space heating and hot water in the 2025 BAU scenario across the various heat densities was selected as an additional parameter. The analyses of the data from Invert/EE-Lab result in the allocation of the energy demand of each municipality to six energy density classes. These six classes are split into areas with densities of:

- less than 6 GWh/km²;
- 6–10 GWh/km²;
- 10–20 GWh/km²;
- 20–35 GWh/km²;
- 35–60 GWh/km²;
- more than 60 GWh/km².

Figure 4-3 illustrates demand for space heating and hot water for all secondary regions in the 2025 BAU scenario, broken down according to the six density classes. It can be observed that the areas with the greatest heat densities are no longer included. The distribution allows three types to be identified. Firstly there is a lower range of municipalities in which more than 50 % of heat volume is situated in the two lowest heat density classes, i.e. below a heat density of 10 GWh/km². Then there is an upper range of municipalities in which more than 50 % of heat demand is situated in the two highest density classes, i.e. in areas with a heat density of more than 35 GWh/km². In the majority of municipalities fulfilling neither of these two criteria, heat demand primarily lies between densities of 10 GWH/km² and 35 GWh/km².

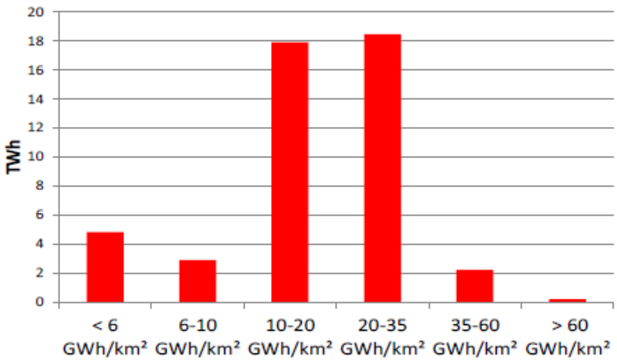


Figure 4-3: Distribution of the heat demand of all secondary regions according to heat density

- Each municipality's **share of existing grid supply volume** is selected as an additional classification parameter. This was determined in the same way as for the calculation of existing district heating systems in the primary regions, namely on the basis of the number of buildings connected to a district heating grid in accordance with the 2001 building and housing census. Figure 4-4 shows the connection rate across the different municipalities in accordance with the 2001 census.[7] It demonstrates that 325 municipalities have a connection rate of more than 5 % of buildings, and 822 municipalities have a connection rate of between 0.5 % and 5 % of buildings. Both of these limit values are used for the purposes of classification. The 1147 municipalities in total hereby identified roughly correspond to the number of existing biomass-fuelled local and district heating grids in Austria, which account for the majority of all existing grids. In the remaining 1220 municipalities, fewer than 0.5 % of buildings are connected to a district heating grid, and are classed as non-grid-connected in line with the definition used here.

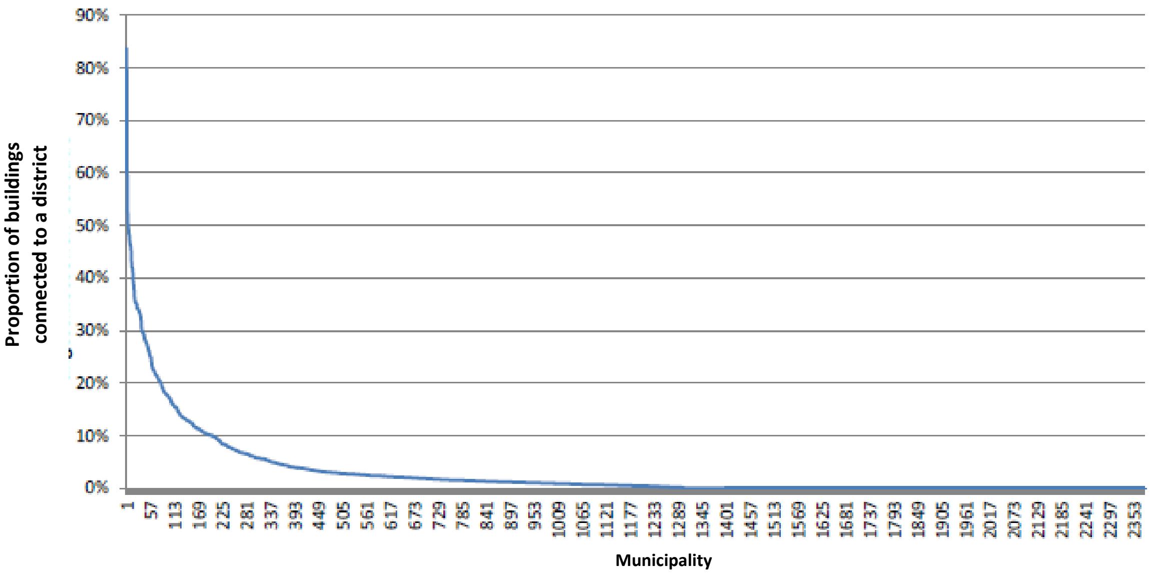


Figure 4-4: Proportion of buildings connected to a district heating grid per municipality according to the 2001 building and housing census (source: 2001 building and housing census, Statistik Austria)

[7] The problem with using the 2001 building and housing census is that heating grids constructed after 2001 could not be taken into account. However, it was not possible to obtain more recent, comprehensive information on heating grids at the time this project was being conducted.

- The next classification parameter used was **availability of the technologies listed below**:

o Gas-fired technologies

In order to classify municipalities as 'gas-supplied' or 'not gas-supplied', the availability of gas in each municipality was determined. This was done by determining the proportion of localised heat demand situated within 2 km of an existing gas pipeline. The thereby determined gas availability value for all Austrian municipalities is presented in Figure 4-5. This figure shows that in around 1000 municipalities, more than 80 % of energy demand is located within 2 km of an existing gas pipeline. In a further 1000 municipalities, less than 20 % of demand can be found within this range. Only 300 municipalities are situated in the transitional zone in which between 20 % and 80 % of demand for space heating and hot water is located within reach of an existing gas pipeline. As a result, a limit value of 50 % is used as a classification criterion. If more than 50 % of energy demand is located within reach of a gas pipeline, the secondary region is classified as gas-supplied, and if more than 50 % of energy demand is located outside of this 2 km radius, the region is classified as not gas-supplied.

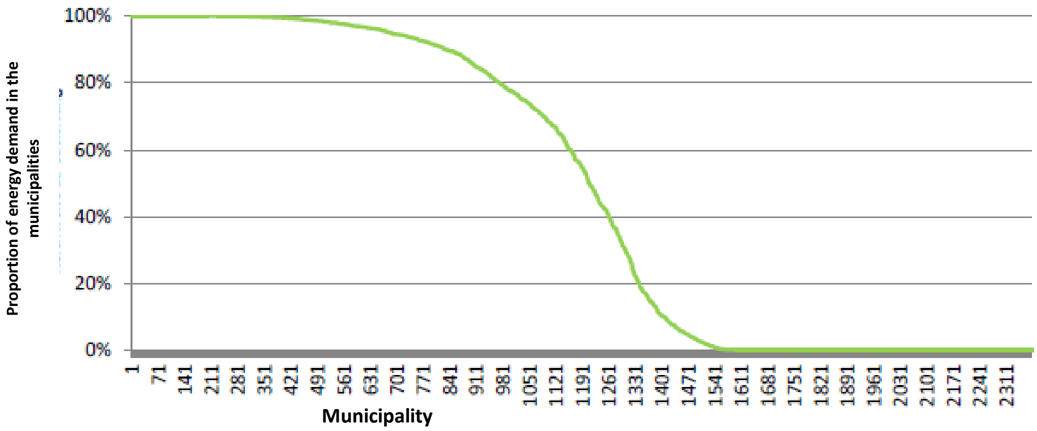


Figure 4-5: Gas availability in Austrian municipalities (source: own calculations on the basis of the e-control gas network map [e-control, 2008])

o Geothermal

As an additional criterion, municipalities are then classified in terms of whether they exhibit technical potential for supplying district heating grids with geothermal energy. As described in Section 4.7.1, the input data for this is the results of the project 'Potential of deep geothermal energy in the field of district heating and electricity generation in Austria' (Könighofer et al., 2014).

o Industrial waste heat

In order to determine whether the municipalities have potential for application of waste heat, the volumes of waste heat produced in industry as calculated in Section 4.5 are used. Figure 4-6 shows the waste heat volumes for all 94 municipalities exhibiting potential for application of waste heat, as well as the total waste heat volume as a proportion of heat demand in each municipality. The figure demonstrates that in some municipalities, there is potential

for total demand to be more than adequately covered through application of waste heat, whereas in others this would cover only a portion of demand. Municipalities with potential industrial waste heat volumes of between 0 % and 100 % of their energy demand are regarded as one class, and municipalities in which more than 100 % of energy demand could be covered by waste heat are regarded as the second. If there is potential for application of waste heat in municipalities forming part of one of the 38 primary regions, the total potential is allocated to the primary region, as it is assumed that these regions are in principle suitable for application of district heating.

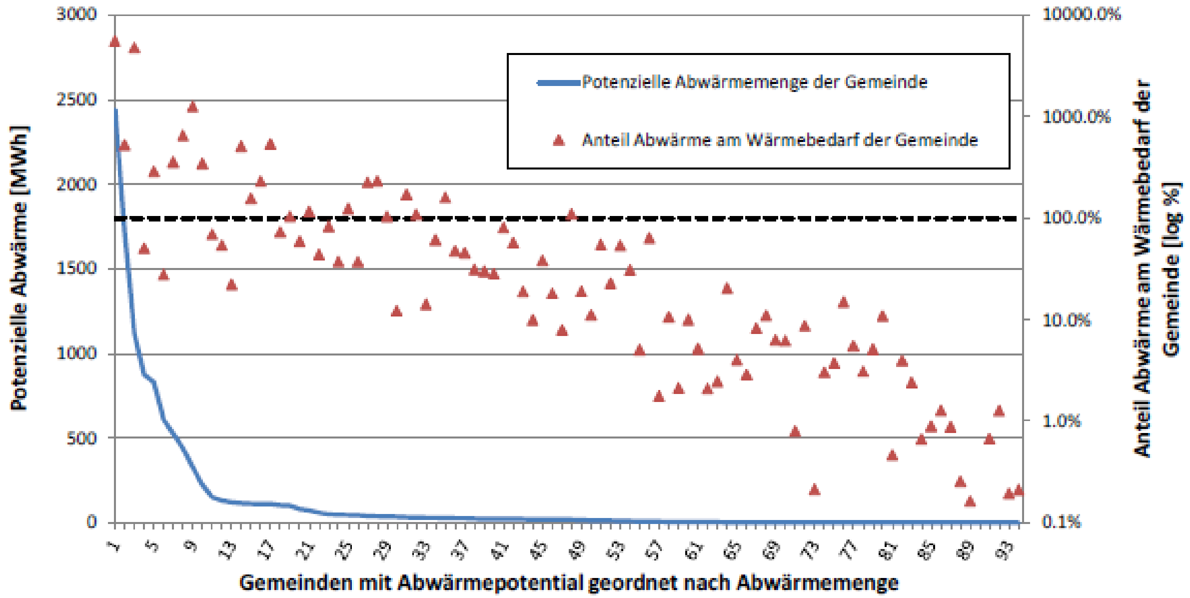


Figure 4-6: Potential waste heat quantities, including as a proportion of heat demand in the municipalities (source: own calculations, see Section 4.5)

Potenzielle Abwärme [MWh]	Potential waste heat [MWh]
Potenzielle Abwärmemenge der Gemeinde	Potential waste heat quantity in the municipalities
Anteil Abwärme am Wärmebedarf der Gemeinde	Waste heat as a proportion of heat demand in the municipalities
Anteil Abwärme am Wärmebedarf der Gemeinde [log %]	Waste heat as a proportion of heat demand in the municipalities [log %]
Gemeinden mit Abwärmepotential geordnet nach Abwärmemenge	Municipalities with potential for waste heat in order of waste heat volume

When this secondary region typology is applied, the classification tree pictured in Figure 4-7 is obtained. If the regions within a particular type are homogeneous enough, no further sub-classification is performed in order to limit the number of types to 30. In the classification tree, each of the characteristics is listed, as is the number of municipalities allocated to this type. All municipalities classed as secondary regions were divided up in this way, and averages were calculated for all municipalities within each type to produce representative values for heat volumes in each density class and for potential. Secondary region types 1 to 5 encompass municipalities located at more than 1000 m above sea level, which are then broken down according to low/medium heat density and according to grid size. Types 6 to 30 encompass municipalities located at less than 1000 m above sea level, and are broken down further into municipalities with a low, medium and high heat density, whereby each sub-group is then sub-divided according to the size of their existing grid. Municipalities with medium energy density, which represent the majority of municipalities, are then further sub-divided according to the availability of technical potential. The outcome of this classification is presented in Figure 4-8. The detailed data used for the typology are available to download from http://www.austrian-heatmap.gv.at.

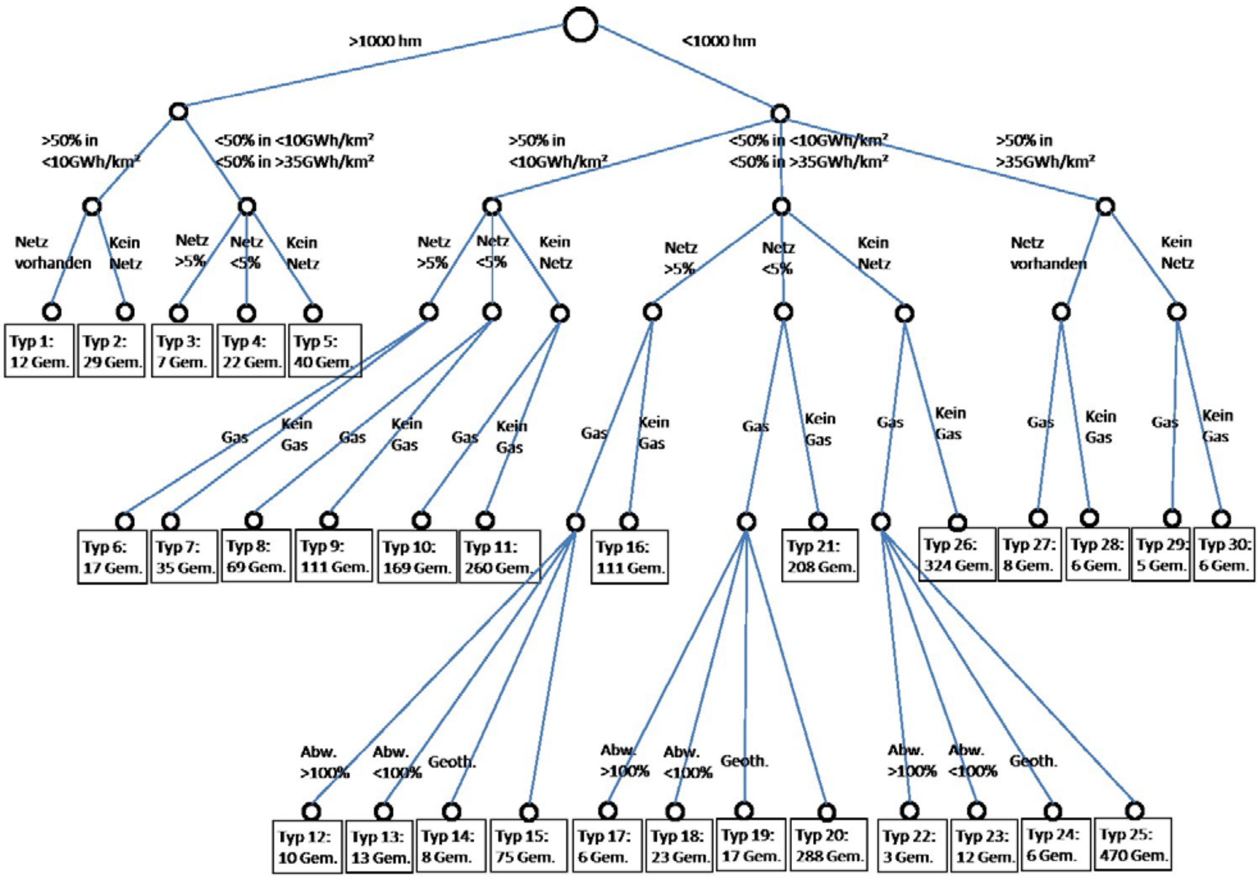


Figure 4-7: Classification tree for determining secondary region types

Netz vorhanden	Grid available
Kein Netz	No grid
Netz	Grid
Gas	Gas
Kein Gas	No gas
Gem.	Mixed
Abw.	Waste heat
Geoth.	Geothermal

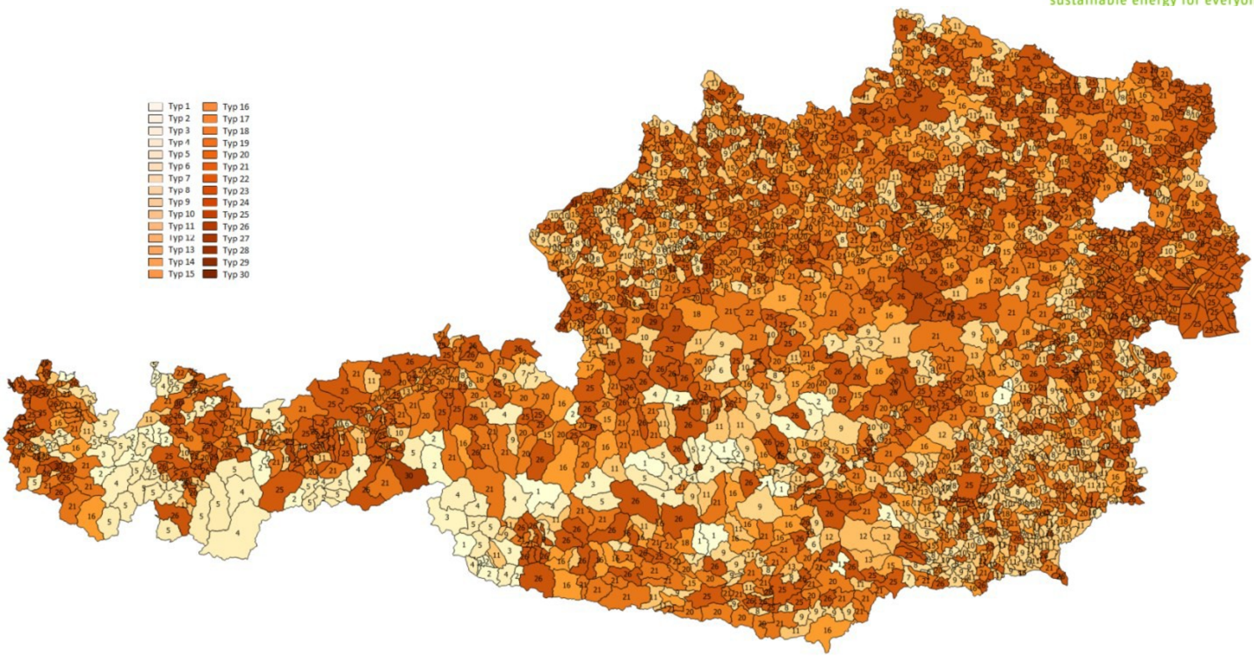


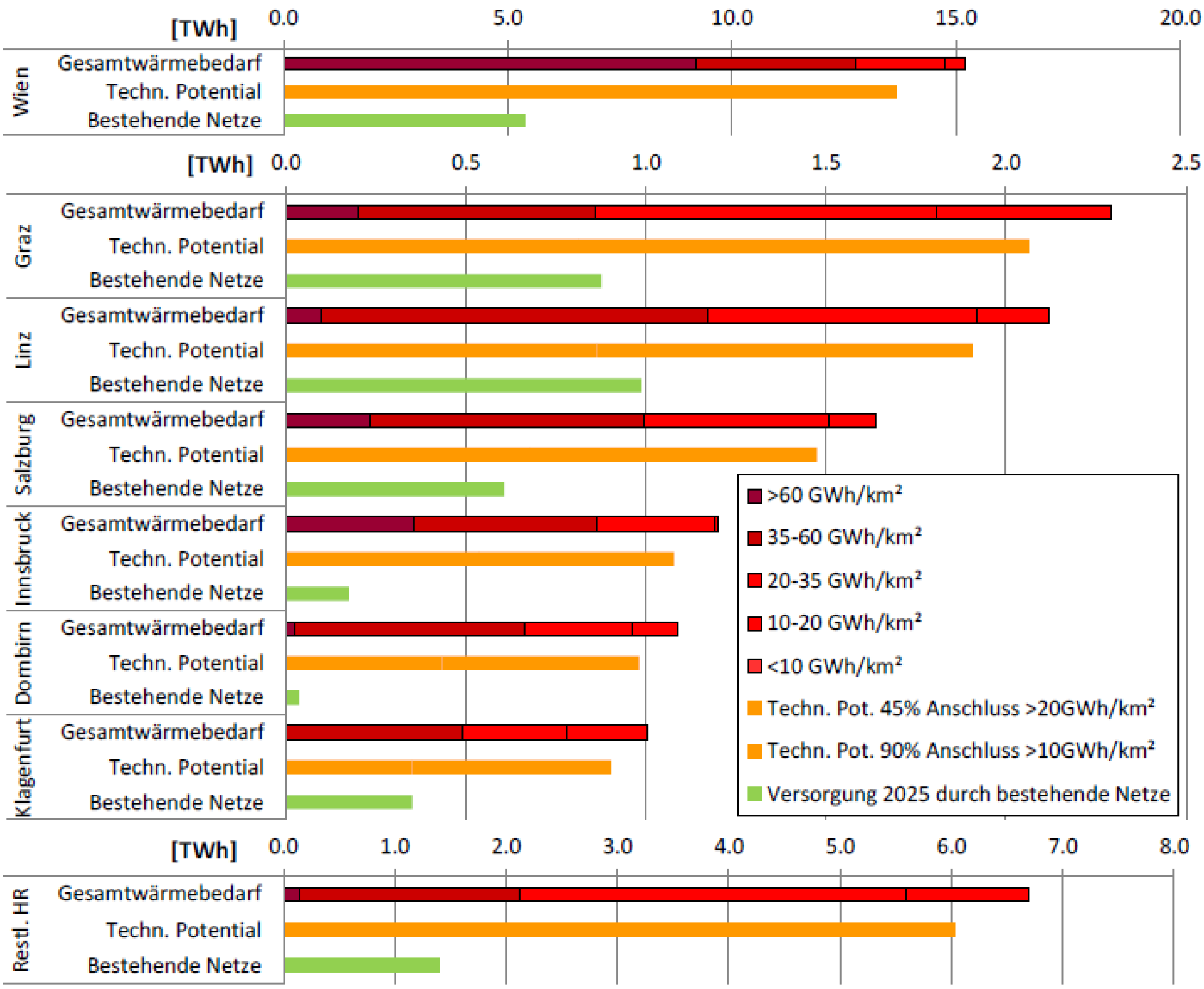
Figure 4-8: Typology of municipalities in Austria

4.3 Technical potential for district heating

4.3.1 District heating potential in primary regions

The technical potential for application of district heating is calculated on the basis of demand for space heating and hot water in 2025 according to the business-as-usual scenario (see Section 2.2.2). Here, it is the proportion of total demand in areas with a heat density of over 10 GWh/km² and where a connection rate of 90 % can be achieved that is taken into account. Figure 4-9 shows total heat demand, two variants of technical potential and the current grid connection rate for the 2025 BAU scenario. Demand for space heating and hot water is given for each of the seven largest primary regions, and as a total for the remaining primary regions according to the heat density classes. The technical potential values given include on the one hand total potential for district heating application in all areas with a heat density of greater than 10 GWh/km² and a connection rate of 90 %, and on the other reduced technical potential in the event of application in all areas with a heat density of greater than 20 GWh/km² and a connection rate of 45 %. In line with their definition, essentially none of the primary regions have heat demand with a density of below 10 GWh/km². According to these criteria, the total technical potential for district heating in the primary regions stands at 28.1 TWh, and the reduced technical potential at 12.8 TWh.

The current grid connection rate serves to illustrate the extent to which this potential is already being exploited. The current connection rate is determined on the basis of the 2001 building and housing census, extrapolated for the year 2012. The rate thereby calculated is taken to apply for the entire scenario period up until 2025. In the 2001 building and housing census, the number of buildings supplied via district heating and the number of residential units supplied via district heating are indicated per municipality. To calculate the number of residential units currently supplied via district heating, an extrapolation was performed on the basis of the 2012 micro-census. Using the data on the proportion of main residences supplied via district heating from the years 2002 and 2012, the rate of increase in each federal state was calculated. At federal state level, therefore, the number of residential units corresponds to available statistical data. Unfortunately, this is not possible at municipality level, as there is no data available on the various development rates in the individual municipalities, nor is there any information about the number of new district heating grids established during this period. For the primary regions, the total number of residential units supplied via district heating in all of the municipalities forming part of each region was added up, and a connection rate was calculated. Subsequently, an individual investigation was conducted into the connection rates and volume of energy sold in each of the primary regions and, if available, these values were compared with the values calculated. Here, a drop in the current volume of heat supplied is assumed in line with the total heat demand calculated for the 2025 BAU scenario. This presents one difficulty, namely that the actual expansion of district heating networks does not correspond to the primary regions identified. Calculated in this way, heat demand already covered by district heating in the 38 primary district heating regions amounts to a total of 9.8 TWh for the year 2025, which corresponds to 31 % of the total heat demand in these regions.



Wien	Vienna
Gesamtwärmebedarf	Total heat demand
Techn. Potential	Technical potential
Bestehende Netze	Existing grids
Restl. HR	Remaining primary regions
Techn. Pot. 45% Ansclus s	Technical potential at 45 % connection rate
Versorgung 2025 durch bestehende Netze	Supply from existing grids in 2025

Figure 4-9: Demand for space heating and hot water according to the 2025 BAU scenario, technical potential for application of district heating and proportion of the primary district heating regions that are already grid-connected

For the purposes of the economic analysis in Section 6, it is necessary to estimate which heat density classes the already grid-connected share falls under. To this end, a simple weighting was applied in order to distribute the grid-connected heat demand across the heat density classes. Figure 4-10 shows the demand for space heating and hot water in the primary regions, broken down according to the six heat density classes. By way of comparison, demand is indicated for the primary region of Vienna, which encompasses not only 23 municipality districts, but also parts of 10 further peripheral municipalities. 90 % of the demand for space heating and hot water in areas with a heat density of more than 60 GWh/km² is attributable to Vienna.

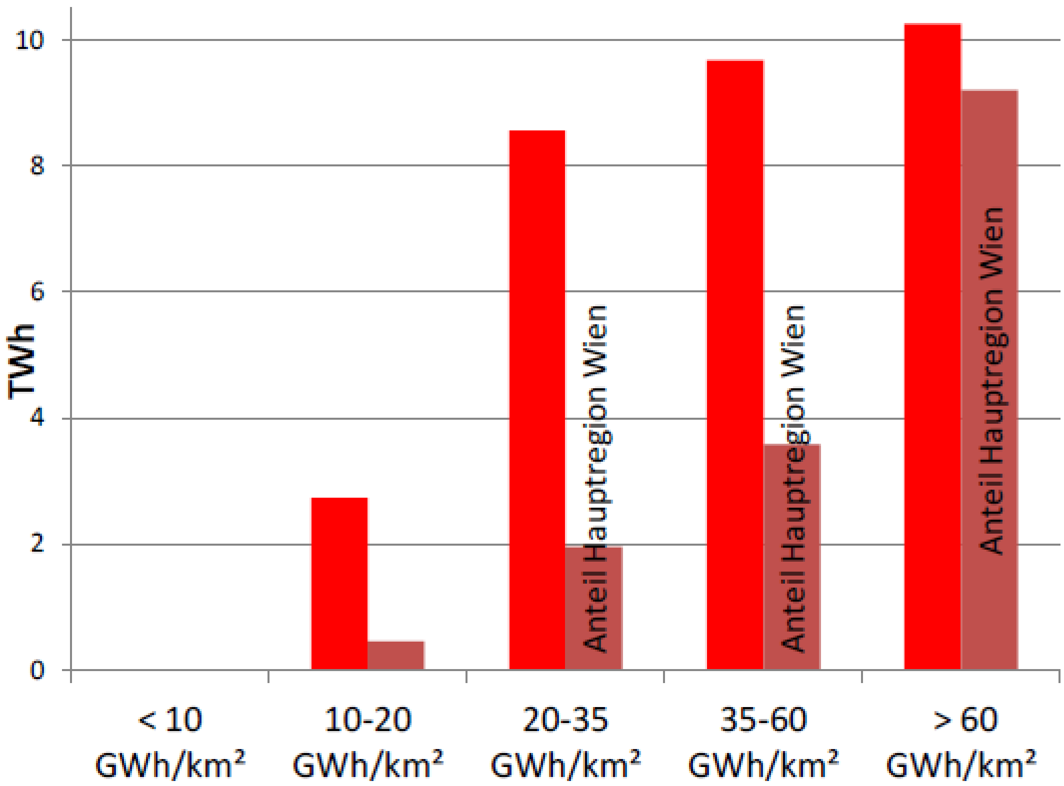
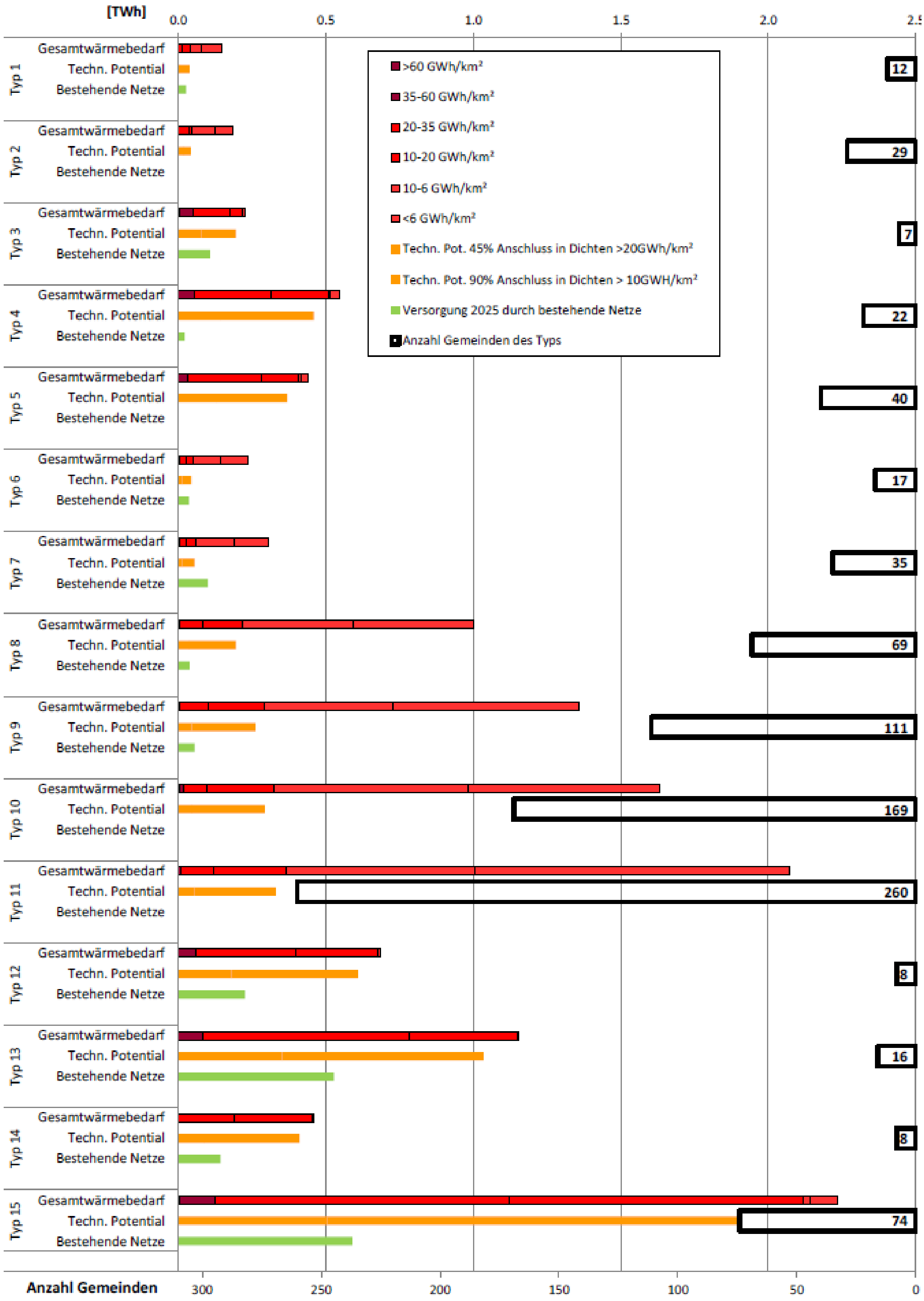


Figure 4-10: Breakdown of heat demand in all primary regions according to heat density, and share accounted for by the primary region of Vienna

Anteil Hauptregion Wien	Share accounted for by the Vienna primary region

4.3.2 District heating potential in secondary regions

The technical potential for district heating in the secondary regions is calculated using heat demand in the same way as for the primary regions. For each of the 30 secondary region types, heat demand is calculated as the sum of the demand for all municipalities falling under that particular type. For calculating the total technical potential, a lower energy density threshold of 10 GWh/km² is applied. Types 1 and 2 and types 6 to 11, in which more than 50 % of heat demand falls in areas with a density of below 10 GWh/km² in line with the classification criteria, therefore exhibit only marginal technical potential for the application of district heating. Figure 4-11 and 4-12 present the total heat demand for each of the 30 types as well as the resulting technical potential per type and the proportion of already grid-connected heat demand. In addition, the number of municipalities per type is indicated. It can be observed that the greatest energy demand occurs in types 20 and 21, and in types 25 and 26 (municipalities with medium energy density that either have no district heating grid or only a very small one, and which either have access to gas or do not), and that most municipalities fall under these types.



Gesamtwärmebedarf	Total heat demand
Techn. Potential	Technical potential
Bestehende Netze	Existing grids
Anzahl Gemeinden	Number of municipalities
Techn. Pot. 45% Anschluss in Dichten >	Technical potential at 45 % connection rate at

	densities of >
Versorgung 2025 durch bestehende Netze	Supply from existing grids in 2025
Anzahl Gemeinden des Typs	Number of municipalities under each type

Figure 4-11: Heat demand and technical potential for district heating, as well as the share of demand covered by already existing grids in 2025 for each of the classified secondary regions: types 1 to 15

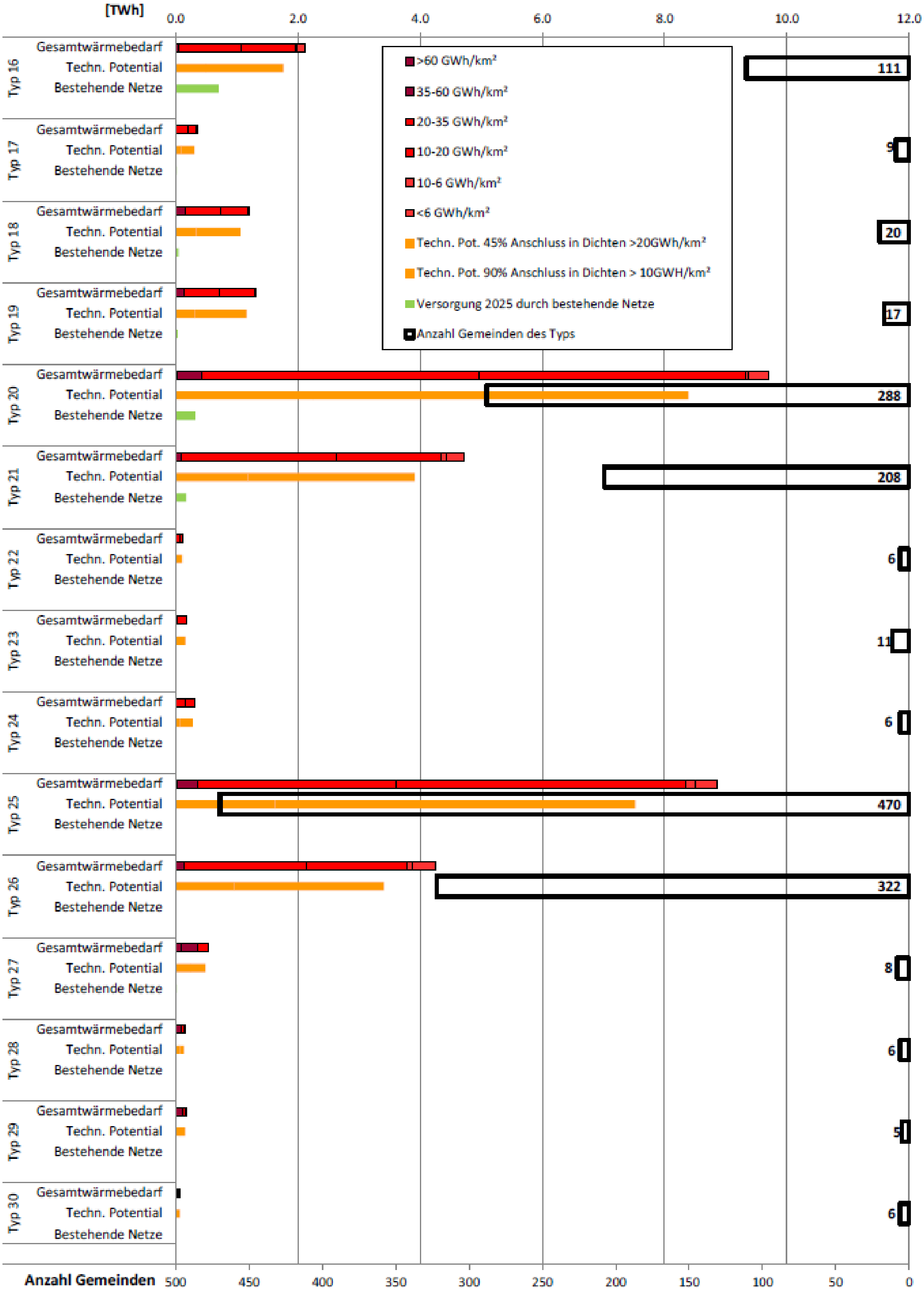


Figure 4-12: Heat demand and technical potential for district heating, as well as the share of demand covered by already existing grids in 2025 for each of the classified secondary regions: types 15 to 30

Gesamtwärmebedarf	Total heat demand
Techn. Potential	Technical potential
Bestehende Netze	Existing grids
Anzahl Gemeinden	Number of municipalities
Techn. Pot. 45% Anschluss in Dichten >	Technical potential at 45 % connection rate for densities of >
Versorgung 2025 durch bestehende Netze	Supply from existing grids in 2025
Anzahl Gemeinden des Typs	Number of municipalities under each type

Figure 4-13 shows a breakdown of heat demand for all secondary regions by heat density class. Compared to the breakdown for the primary regions, it can be seen that only a small proportion of demand for space heating and hot water is attributable to the two highest density classes.

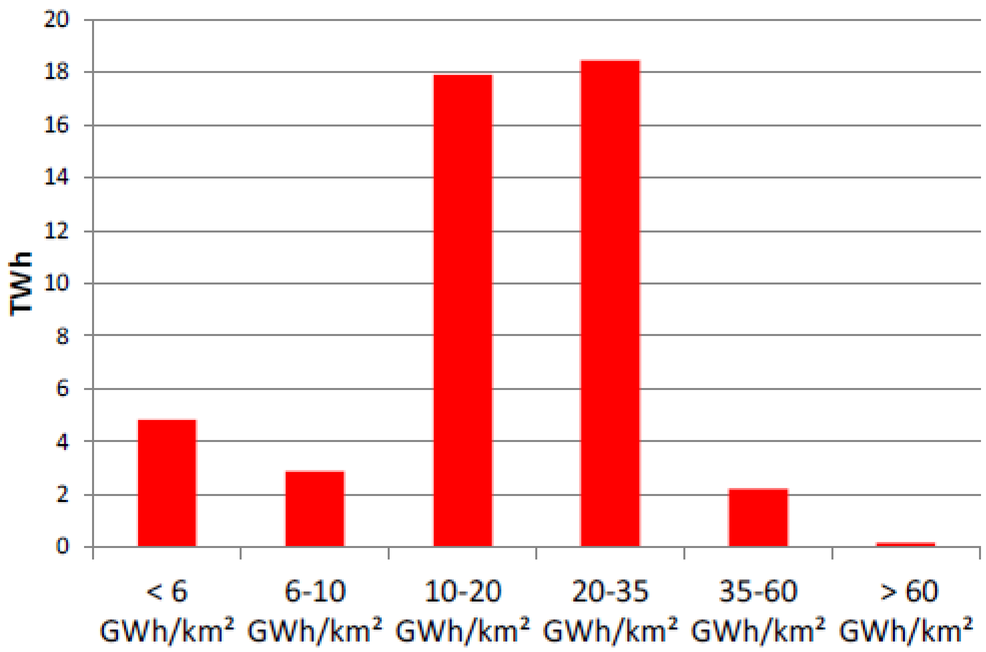


Figure 4-13: Breakdown of the heat demand of all secondary regions in the 2025 BAU scenario according to heat density

4.4 Technical potential for cogeneration

The technical potential for cogeneration is assessed separately for cogeneration plants connected to heating grids (Sections 4.4.1 to 4.4.3) and industrial cogeneration plants (Section 4.4.4).

The potential analysis for generation of heat by grid-bound cogeneration plants is first performed on the basis of the heat demand and heat load profiles of the primary and secondary regions. The analysis is based on the simulated heat demand for the 2025 BAU scenario (see Section 2.2.2), in which the total demand for space heating and hot water in Austria amounts to roughly 85 % of heat demand in the baseline year 2012. A distinction is made between technical potential in regions which already have district heating grids and technical potential in the event of a full roll-out of heating grids. First, a technical maximum potential for all primary and secondary regions is calculated. This is based on an assumed connection rate of 90 % in all areas with a heat density of >10 GWh/km2. To this end, it is assumed that the cogeneration plants are of a size whereby 10 % of the peak heat load is covered by additional peak load boilers. These plants are assumed to be designed and operated as purely heat-controlled facilities. Depending on the heat load profiles of the regions, this results in estimated total full-load hours in cogeneration plants of between 4300 h/a and 5600 h/a. Electricity prices and the resulting optimal operating mode for cogeneration plants are not taken into account until the calculation of economic potential in Section 6. There, the maximum technical potential is included as a restriction in the subsequent economic analyses. Next, a reduced technical potential for application of cogeneration is calculated. This is based on an assumed connection rate of only 45 %. In addition, it is assumed that only areas with heat densities of >20 GWh/km2 would be supplied via district heating.

The technical maximum potential for application of cogeneration throughout Austria resulting from these assumptions stands at 10.2 TWh_{th} in existing heating grids. In the event of full roll-out of heating grids in all primary and secondary regions, the total potential would rise to 57 TWh_{th}. 44 % of the maximum potential is located in the identified primary regions (see Section 4.2), and 28 % in primary regions with heat densities of >35 GWh/km2. It is far more likely that the cogeneration potential will be realised in these areas than in areas of secondary regions with heat densities of 10–35 GWh/km2 in which 52 % of the maximum technical potential can be found.

The reduced technical potential stands at 21.4 TWh, which corresponds to only a little more than one third of the maximum potential. In addition to the halving of the heat volume required due to the low connection rate in newly-supplied areas, potential is primarily reduced in secondary regions due to the large proportion (approx. 46 %) of areas with heat densities of <20 GWh/km2, a category which encompasses only a very small proportion of the primary regions (<9 %).

A comparison with current production data indicates that the technical potential of existing heating grids is already largely exhausted, and a significant increase in the heat supplied by cogeneration would primarily involve an expansion of those heating grids. Depending on efficiency gains in buildings and the age structure of power plants, generation-side over-capacity may arise in certain district heating regions if the heating grids are not expanded or if density within the grids is not increased. The detailed results for primary and secondary regions are provided below. The results for maximum technical potential (90 % connection rate in areas >10 GWh/km2) are provided, broken down by heat density.

4.4.1 Breakdown by primary and secondary regions

The technical potential for grid-bound cogeneration in the defined primary regions stands at 10.2 TWh_{th} for existing grids. In the event of full realisation of the technical district heating potential in the primary regions, an additional maximum technical potential of 18 TWh_{th} is achieved, resulting in a total technical potential of 25.3 TWh_{th} (44 % of total potential) for the supply of heat from cogeneration should the required heating grid structure and connection rate be attained. Figure 4-14 presents the results for the 7 largest primary regions and for the remaining primary regions, broken down by heat density. It can be observed that almost two thirds of the calculated potential for the primary regions is found in areas with heat densities of >35 GWh/km2, thereby indicating the existence of promising potential for cost-effective application should the necessary underlying conditions be met. There is a fall in the reduced technical potential value to 12.7 TWh_{th}, primarily as a result of the assumed lower connection rate in additional areas of the primary regions.

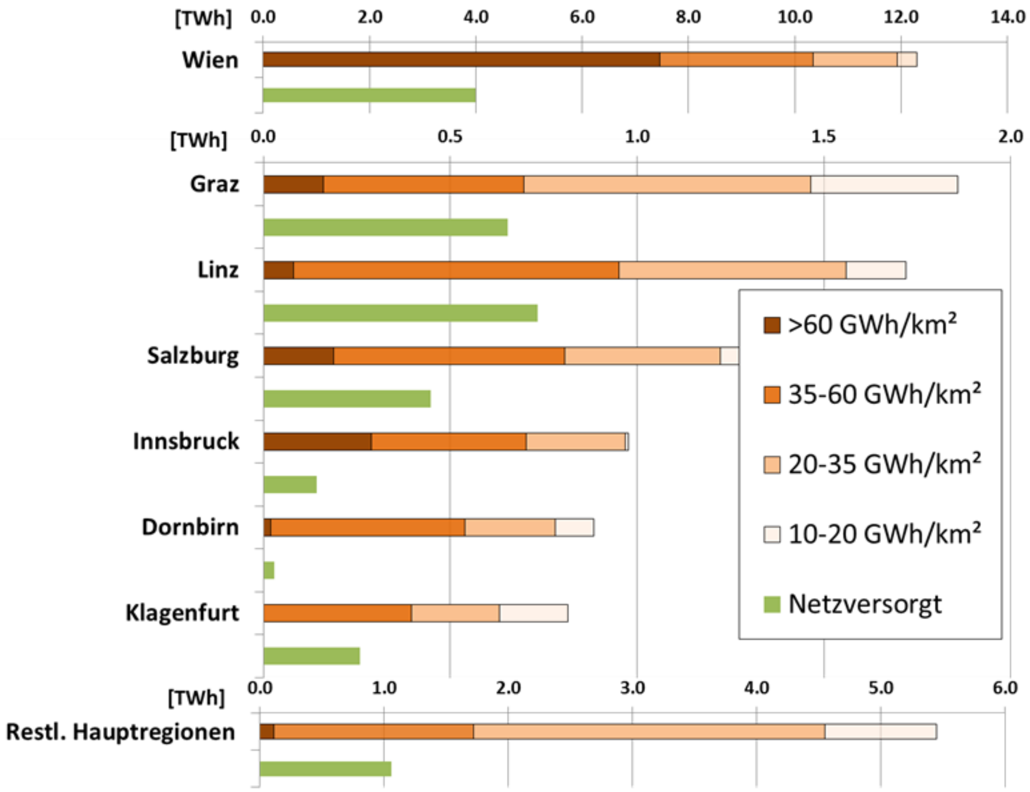
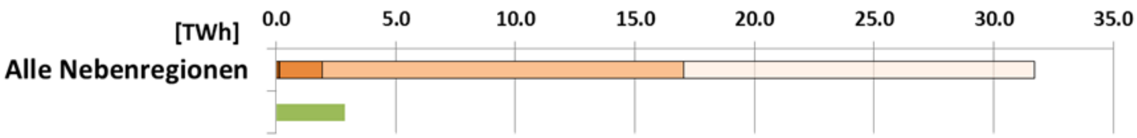


Figure 4-14: Technical potential for heat production through cogeneration in the primary regions for existing grids and in the event of full roll-out of district heating

Wien	Vienna
Netzversorgt	Grid-connected
Restl. Hauptregionen	Remaining primary regions

In the secondary regions considered, the potential for cogeneration in existing grids stands at 2.9 TWh_{th}, as the share of district heating is very low here. In the event of a hypothetical full roll-out of smaller heating grids in all areas with a heat density of >10 GWh/km_2, the cogeneration potential would increase to 31.7 TWh_{th}. From an economic point of view, however, this scenario must be regarded as highly unlikely due to increased distribution costs and smaller plant sizes (see Section 6). It appears that more than 90 % of potential in secondary regions is situated in areas with heat densities of <35 GWh/km2, and approximately 47 % in areas with heat densities of <20 GWh/km_2. As such, the reduced technical potential for the secondary regions stands at only 8.7 TWh_{th}. Figure 4-15 presents the maximum technical potential for the supply of heat through cogeneration, and a breakdown of potential according to the secondary region types defined in Section 4.2 can be found in Figure 4-16.



Alle Nebenregionen	All secondary regions

Figure 4-15: Technical potential for heat production through cogeneration in the secondary regions for existing grids and in the event of full roll-out of district heating in areas with a heat density of >10 GWh/km2

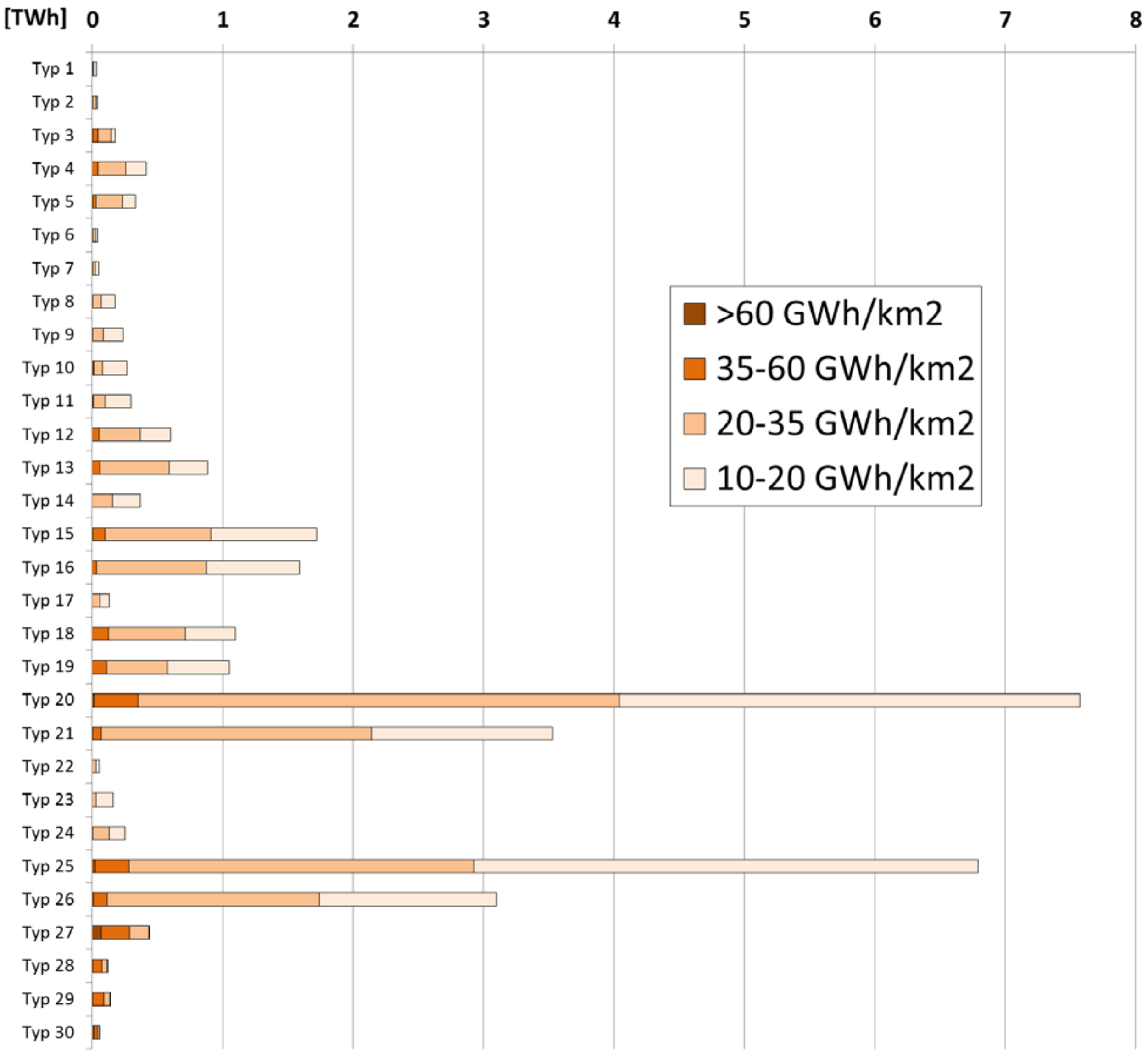


Figure 4-16: Maximum technical potential for heat production through cogeneration in the secondary regions in the event of full-roll out of district heating, broken down by the classified regions according to their heat density

4.4.2 Estimation of resulting electricity generation

Alongside heat demand, an additional limitation of technical potential that should be taken into account is demand for electricity. Whereas a detailed analysis of the operating mode of cogeneration plants is carried out for the purpose of calculating economic potential in Section 6, only a rough estimate of resulting electricity generation in the event of heat-controlled operation of all cogeneration plants is provided here in order to illustrate the restrictions arising from electricity generation at cogeneration plants in Austria. To this end, assumptions are made for various CHP coefficients depending on heat demand, whereby lower coefficients are assumed for smaller heating grids (see Table 4-2). The cogeneration plants are then classified in terms of their thermal peak capacity and the assumed CHP coefficients.

Table 4-2: Assumed CHP coefficients depending on plant size

	< 1 MW_{el}	1 to 10 MW_{el}	10 to 100 MW_{el}	> 100 MW_{el}
Assumed CHP coefficient	0.49	0.6	0.83	1.32

On the basis of these assumptions, a technical potential for electricity generation from cogeneration in areas with existing heating grids of 10 TWh_{el} is calculated, whereby this potential is almost exclusively attributable to the primary regions. In the event of full roll-out in all regions with heat densities of more than 10 GWh/km^2, the theoretical potential would amount to 49.2 TWh_{el}, whereby over 60 % of the total technical potential for electricity generation from cogeneration is attributable to the primary regions. This is due not only to the high share of total heat demand accounted for by these regions, but also due to the higher potential CHP coefficients in larger cogeneration plants (primarily gas and steam plants generating >100 MWel). In the reduced technical potential scenario, estimated electricity offtake stands at 18.9 TWh_{el}.

Taking into account the production structure for electricity in Austria, whereby a large share of domestic electricity consumption is covered by hydropower and additional generation from regenerative energy[8] (approx. 63 % of domestic electricity consumption of 69 TWh_{el} in 2014), it emerges that full exploitation of potential for cogeneration would more than cover average annual electricity demand, meaning that the technical potential for application of cogeneration in the area of heating is limited by electricity demand. On the basis of a thermal generation percentage of 37 %, a maximum demand for cogenerated electricity of 25.5 TWh_{el} emerges.[9] In addition, residual electricity demand with potential for being covered by CHP plants is falling due to the further roll-out of fluctuating renewables. This would either result in fewer full-load hours for all CHP plants or a limited potential for the construction of new plants. At all events, it is clear that provision of heat through cogeneration only becomes useful where this is a substitute for inefficient fossil-fuel power stations. In cases where renewable energy sources account for a large share of the electricity system, this is not always the case. Figure 4-17 shows demand for electricity in Austria in 2012, broken down by hour (blue). The figure also presents aggregated heat demand in areas which already have heating grids and the resulting electricity offtake of exclusively heat-controlled cogeneration plants (red). To this end, the total hourly feed-in of energy from run-of-river power stations, PV and wind power is calculated for the year 2012.

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[8] Share of hydropower, including storage but minus electricity demand from pumped storage plants: approx. 57 % of domestic electricity demand.
Share of other renewable energy sources: approx. 6 % of domestic electricity demand.
See: http://www.e-control.at/statistik/strom/betriebsstatistik/betriebsstatistik2014

[9] By way of simplification, it is assumed here that exports are only possible to a limited extent and that the proportion of generated energy imported/exported remains unchanged. The share of cogenerated electricity could be increased through exports. However, it should be borne in mind that there are also limits to export capacity due to increased usage of cogeneration in neighbouring countries and further roll-out of renewable energy sources.

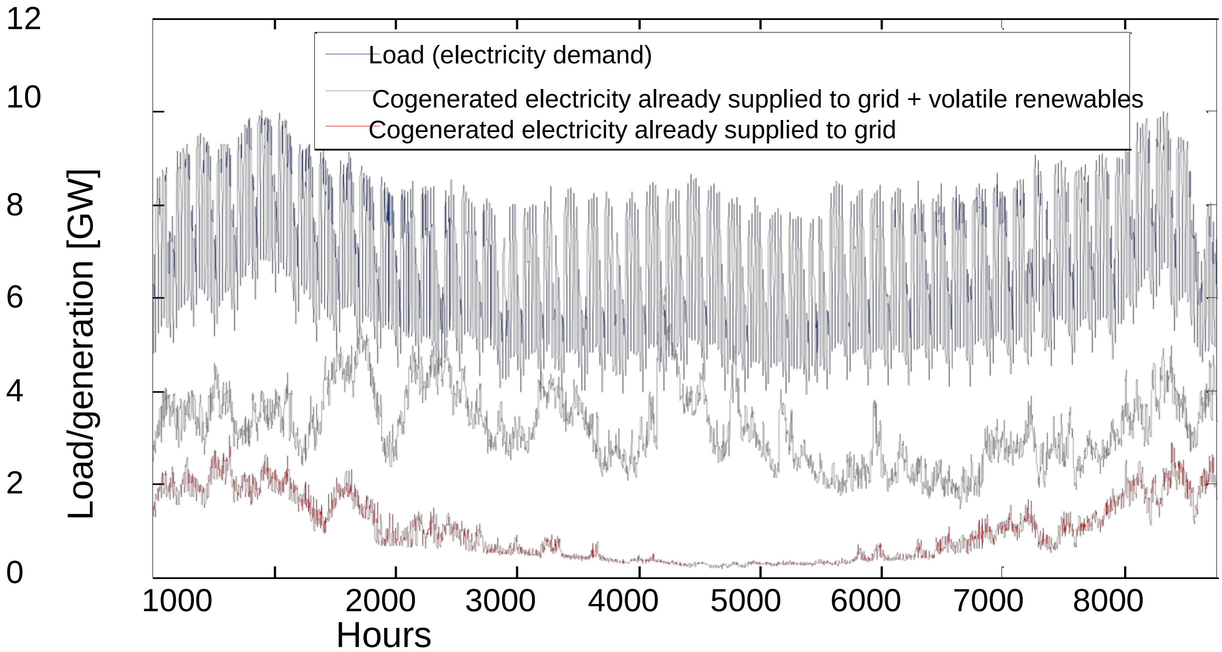


Figure 4-17: Electricity demand, simulated heat-controlled cogeneration and supply generated using renewable energy sources in Austria in 2012. Cogenerated electricity refers to electricity generated through exploiting technical cogeneration potential in areas already supplied via heating grids. Source: own calculations

It can be observed that the resulting volume of electricity produced would only exceed demand on a small number of occasions. If cogenerated electricity accounted for 14 % of total electricity demand in Austria, this would result in a total surplus of only 0.4 TWH_{el} (see Table 4-3). The estimated volume of cogenerated electricity can therefore be almost entirely absorbed by the electricity system.[10] However, in the event of increased application of cogeneration, electricity demand would represent a limitation to any further developments (see also Erdmann, 2010). Figure 4-18 presents a graded duration curve for electricity demand (load) and residual loads upon subtraction of electricity generated through run-of-river power stations, PV and wind power as well as for cogenerated electricity according to different levels of exploitation of the technical potential. Table 4-3 also lists the cogenerated electricity volume as a proportion of total electricity demand as well as the resulting surpluses in the event of purely heat-controlled operation. It emerges that increasing the maximum potential may in some cases lead to large electricity surpluses (>10 GW), meaning that it would not be possible for all of the electricity to be absorbed by the system, even taking into account export capacity. If cogeneration accounted for 52 % of total electricity production, a surplus of 18 TWh_{el} would be generated, which is equivalent to 36 % of the total volume of cogenerated electricity produced through purely heat-controlled electricity generation.[11] Full exploitation of the reduced technical potential results in 28 % of total demand for electricity being met by cogeneration plants with surpluses of 2.2 TWh_{el}. If the flexibility of the system was increased accordingly by way of heat storage systems, and if a sufficient number of cogeneration plants had flexible CHP coefficients, this option seems far more feasible. Furthermore, Figure 4-18 illustrates how cogenerated electricity is also available during peak load periods, meaning that a build-up of cogeneration plants would lead to a significant reduction in demand for additional peak load capacity in the field of electricity.

[10] Once again, it should be noted that this is based on the assumption that a purely heat-controlled operating mode is being applied. In practice, due to current low electricity prices and as a result fewer full-load hours, the share of cogenerated electricity would be lower than indicated in the figures if alternative heat supply methods were available.

[11] Even though, from a purely technical point of view, these surpluses could be partially absorbed through expanding storage capacity, ensuring flexible operation and reinforcing transmission networks, it is highly unlikely, from an economic point of view, that the system could be designed to fully absorb such large quantities.

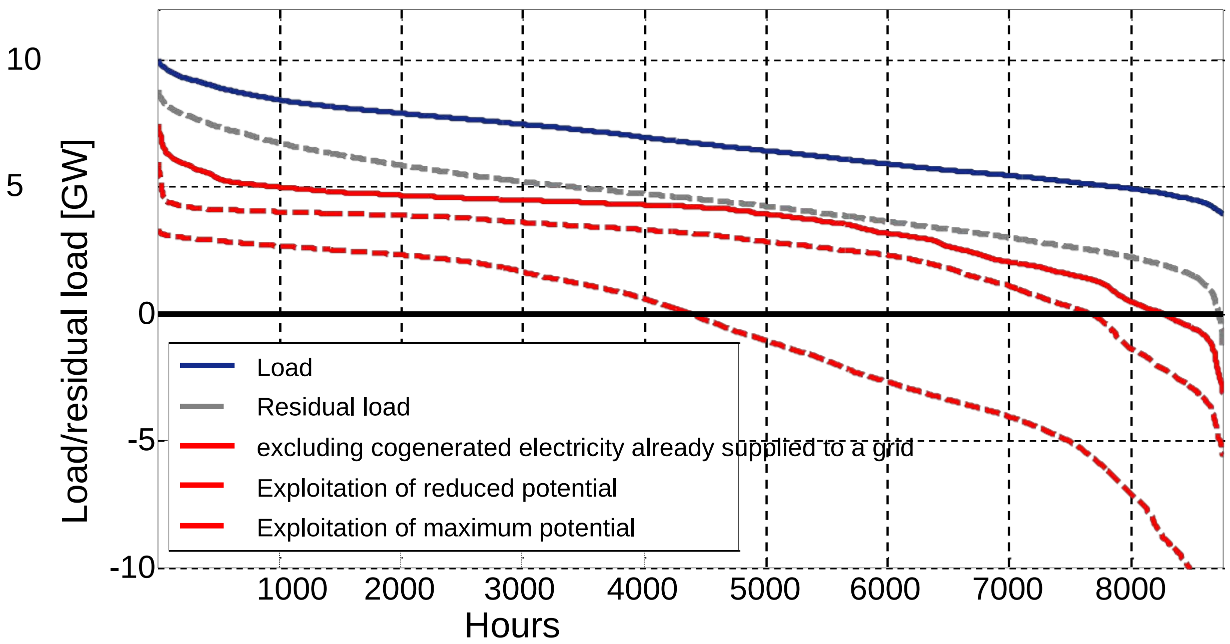


Figure 4-18: Graded duration curves for electricity demand, residual load excluding renewables, residual load excluding cogenerated electricity at various levels of exploitation of the calculated technical potential and in the case of purely heat-controlled operation.

Table 4-3: Share of cogenerated electricity and surpluses at various levels of exploitation of potential

	Already supplied to a grid	**Exploitation of reduced technical potential**	**Exploitation of maximum technical potential**
Cogenerated electricity as a share of total electricity	14 %	28 %	52 %
Surplus [TWh_{el}]	0.4	2.2	18

On a functioning electricity market, the demand for conventionally generated electricity and cogenerated electricity should be reflected in the hourly price of electricity, and should thereby influence usage of cogeneration. Measures to increase flexibility should also be rendered cost-effective by fluctuations in electricity prices. Therefore, if the investment costs and fuels used to power the various technologies are priced correctly, an economic analysis should give rise to solutions that are also efficient from a technical perspective, whereby the technical potential is only developed to the extent that it is possible to push inefficient power stations out of the market upon a sufficient number of hours per year being reached. However, regulations and subsidies, both on the heating and electricity side, sometimes offset these signals. As such, all market interventions must take into account the compatibility of electricity and heat provision and the need to encourage flexibility.

It should also be noted, though, that market signals currently favour electricity production from coal-fired power stations due to relatively low coal and CO_2 prices, meaning that gas-fired CHP plants generating low-emissions electricity are being forced out of the market and that there are therefore no incentives to invest in additional gas-fired cogeneration facilities. As such, market incentives run counter to the energy policy objective of reducing CO_2 emissions by increasing the share of electricity produced through cogeneration.

4.4.3 Breakdown by plant size

The technical potential of grid-bound cogeneration varies for different sizes of power station depending on the size of the area to be supplied and the structure of the grid. The aforementioned assumptions regarding the CHP coefficient also apply in this case. Figure 4-19 shows the technical potential for supplying cogenerated heat according to the estimated output classes of the power stations (in MW_{el}) for areas already connected to a grid, and in the event of exploitation of the maximum or reduced potential. Under the existing grid structure, the potential for heat generation in CHP facilities is largely restricted to power stations with an output of more than 100 MW_{el} (67 %). If the maximum potential is fully exploited, there is major potential for increasing capacity in the 1–10 MW_{el} size class (47 % of total potential). This is due to the major theoretical potential for development in smaller secondary regions. However, exploitation of this potential for increasing capacity is less feasible for smaller plants (<10 MWel) than for higher output classes due to the higher specific costs associated with the former. In the reduced technical potential scenario, this potential decreases in this output class both in absolute (from 27 TWh_{th} to 2.4 TWh_{th}) and relative terms (from 48 % to 11 % of total potential). This results in a shifting of potential towards very small grids with potential plant sizes of <1 MW_{el} (7.1 TWh_{th}, equivalent to 33 % of total reduced technical potential), the exploitation of which appears less cost-effective than expanding capacity in the upper output classes.

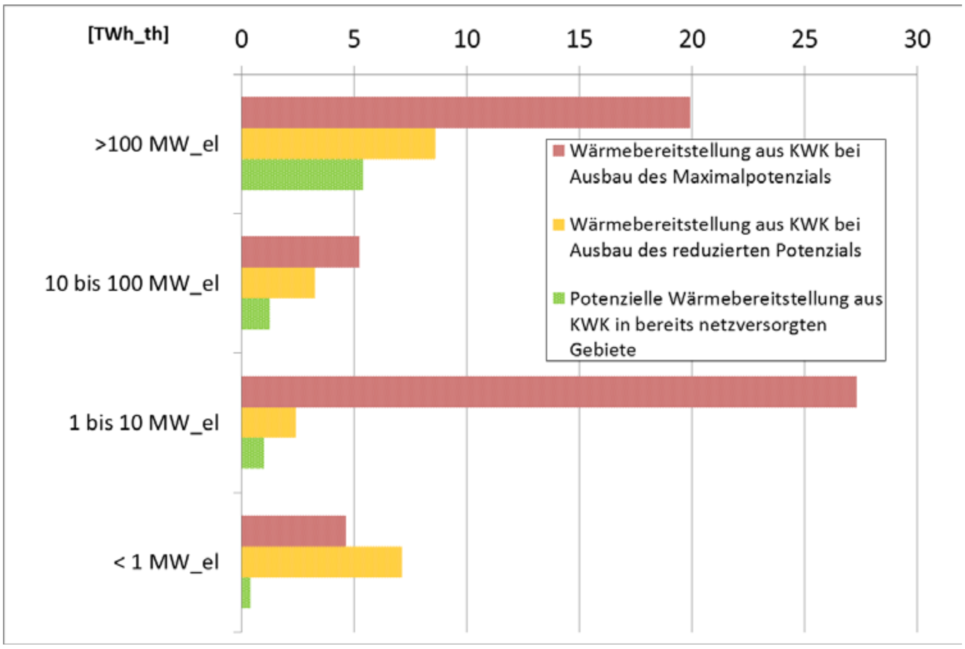


Figure 4-19: Breakdown of technical potential according to plant size upon exploitation of the maximum or reduced technical potential

Wärmebereitstellung aus KWK bei Ausbau des Maximalpotenzials	Heat supply from cogeneration upon exploitation of maximum potential
Wärmebereitstellung aus KWK bei Ausbau des reduzierten Potenzials	Heat supply from cogeneration upon exploitation of reduced potential
Potenzielle Wärmebereitstellung aus KWK in bereits netzversorgten Gebiete	Potential heat supply from cogeneration in already grid-connected areas
bis	to

4.4.4 Cogeneration potential – industrial facilities

This section attempts to estimate the volume of in-house heat demand that can be covered through cogeneration. The calculation of the technical potential for application of cogeneration in industrial companies is based on the following assumptions. All in-house demand for heat up to a maximum temperature of 500°C can be covered through cogeneration. This encompasses process steam, hot water and service water, space heating and furnaces operated at a temperature of up to 500°C. In sectors in which a large proportion of heat demand exceeds 500°C and in which technical potential for internal usage of waste heat from these processes is likely to exist, no technical potential for cogeneration is estimated. This concerns metal production as well as the manufacture of cement, lime and bricks. The technical potential of industrial cogeneration is based on the calculated heat demand for the year 2025 with efficiency gains in line with the business-as-usual scenario.

Here, heat demand was broken down by temperatures of over and under 500°C and by output classes of larger and smaller than 5 MW of thermal energy on the basis of a range of sources. Using sector-specific heat demand values per employee and the distribution thereof across the different size classes and temperature levels (Blesl, M. et al., 2008) a breakdown by temperature level and output class was performed on the basis of the 2011 Workplace Census and the 2012 Useful Energy Analysis. For companies participating in the ETS, demand for heat at <500°C was estimated on the basis of an analysis of the processes and extrapolated heat demand values. In addition, in order to further ensure the plausibility of the data, a study of temperature distribution in German industry (Nast et al., 2010) was converted for Austria. In the chemicals industry, substantial differences emerged between the first two estimates and the conversion performed using the German study. These discrepancies can first and foremost be traced back to differences in the structure of the sector in Austria and Germany. As such, demand for heat below 500°C was estimated at 85 %.

Table 4-4 lists the technical potential for in-house cogeneration systems in Austrian industry by sector up until 2025.

Table 4-4: Technical potential for application of cogeneration in Austrian industry by sector up until 2025

[GWh/a]	Potential heat >5 MWth	Potential heat <5 MWth	Potential electricity >5 MWth	Potential electricity <5 MWth
Chemicals industry and mineral oil processing	9102	297	3382	110
Vehicle construction	293	207	120	85
Manufacture of machinery and equipment n.e.c.	1591	3479	617	1349
Food materials industry	429	2469	170	977
Pulp and paper industry	11,444	-	3819	-
Wood processing	1288	3075	361	861
Textiles and leather	-	243	-	98
Total	**24,146**	**9770**	**8468**	**3481**

4.5 Technical potential for waste heat recovery

For the companies participating in the ETS, potential heat quantities that could be recovered by external heating grids are estimated below. These estimations were performed on the basis of the extrapolated heat volumes required at each site (see 2.1.2 and 2.2.4). These are primarily drawn from two studies on the potential waste heat potential in various sectors and plant types. Enova (2009) provides the detailed results of a survey in Norwegian industry. The special feature of this study is that, on the one hand, a breakdown by temperature level is provided in each case, and on the other the study achieved a response rate of around 70 %, with the reporting companies accounting for just as large a share of Norwegian industry. McKenna and Norman (2010) investigated waste heat potential in British ETS companies. They performed estimates on the basis of potential usable flue gas flows at the appropriate temperature as well as usable heat from various process sub-steps not involving the use of flue gas.

In the present study, both sources were applied to Austrian companies and compared with available studies conducted at national or regional level, including Niedermair et al. (2012), Schnitzer et al. (2012) and VÖZ (2009). In the case of major discrepancies, the more conservative values were selected for use in further analyses. The waste heat quantities hereby estimated are then reduced by the volume of heat that would no longer be usable externally at a temperature of 100°C or 40°C without also making structural adjustments to process management.

Heat quantities from any in-house cogeneration systems in which fuels required for the production process are used, and where the heat quantities generated cannot be used in-house, are counted as external waste heat in this study.

As with the extrapolation of the heat demand of individual sites, when estimating the potential externally usable waste heat volumes, site-specific factors can only be taken account of in the estimations to a certain degree, meaning that only average conditions are reflected. Moreover, due to the level of detail required for this investigation, the studies primarily used are not based on Austrian companies.

The resulting ranges of waste heat potential were discussed with industry representatives and, in some cases, with individual companies. If more detailed data was available from the companies, these were included in the analysis. However, it should be stressed that it was not possible to carry out any detailed analyses of individual companies in this project. This would have required on-site and other specific investigations into the technical and economic feasibility of waste heat usage.

When interpreting the figures, particular emphasis should also be placed on the term 'technical potential'. This term does not primarily take into account economic restrictions, but instead focuses on technical feasibility. However, the distinction between technical and economic restrictions is not always clear when it comes down to the details. When calculating technical waste heat potential, therefore, it was assumed that no major changes in the production process would be required in order to use the waste heat, and that investments would primarily need to be made in the connection of the system to the heating grid and in exploitation of the heat source in-house. Here, it should be borne in mind that the time frame of the potential analysis runs until 2025. Over the longer term, it may well be possible to exploit even greater potential.

Table 4-5: Technical potential for application of waste heat in Austrian industry by sector up until 2025

[GWh/a]	Potential >100°C	Potential <100°C	Currently fed in
Metals production or processing	1279	184	251
Chemicals industry and mineral oil processing	707	3826	905
Non-metallic minerals	415		22
Manufacture of machinery and equipment n.e.c.,	1	10	
Food materials industry	0	11	
Pulp and paper industry	382	4121	228
Wood processing	44	317	136
Total	**2828**	**8469**	**1542**

4.6 Technical potential for biomass

The potential for biomass was determined on the basis of the project Regio Energy (Stanzer et al., 2010). In order to calculate the energy potential at district level, only the forestry sector was considered as a supplier of firewood due to the state of the available data. Further potential sources of wood such as field shrubs, roadside timber or timber arising from the revitalisation of meadow orchards and wood from vines were not included in the analysis.

The technical potential takes account of the total potential logging volume according to the Austrian National Forest Inventory, regardless of the use type. The reason for this is that no organic substance containing more than 5 % organic carbon may be landfilled in line with the Waste Management Act [Abfallwirtschaftsgesetz, AWG]. As such, any raw material made of wood must undergo treatment in accordance with the AWG before going to landfill. In this analysis, it is assumed that the wood is subjected to thermal treatment (imports and exports are not taken into account). In order to calculate the technical energy potential, a distinction is made between softwood, soft deciduous wood and hardwood. On the basis of the 2000/2002 Forest Inventory, which was used as a source in the Regio Energy project at the level of district forest inspections, potential was broken down into districts using the land register. Dry weight and raw energy content is calculated taking into account the calorific value per kg and the dry density per solid cubic metre for softwood, soft deciduous wood and hardwood.

On the basis of the assumptions described above, approximately 31 TWh of potential fuel energy would be available from forest biomass in the year 2020 in line with the 'midi scenario' described in the Regio Energy project.

In order to calculate potential at the level of the primary and secondary regions, potential for each district was attributed to each of the municipalities in that district in line with the demand for space heating and hot water. For the primary regions, the potential values for all municipalities forming part of those regions were totalled. For the secondary regions, the potential for each of the municipalities was used.

Figure 4-20 shows the potential for heat generation from forest biomass for each district as calculated by the Regio Energy project, which forms the basis for the potential restriction calculations in this study.

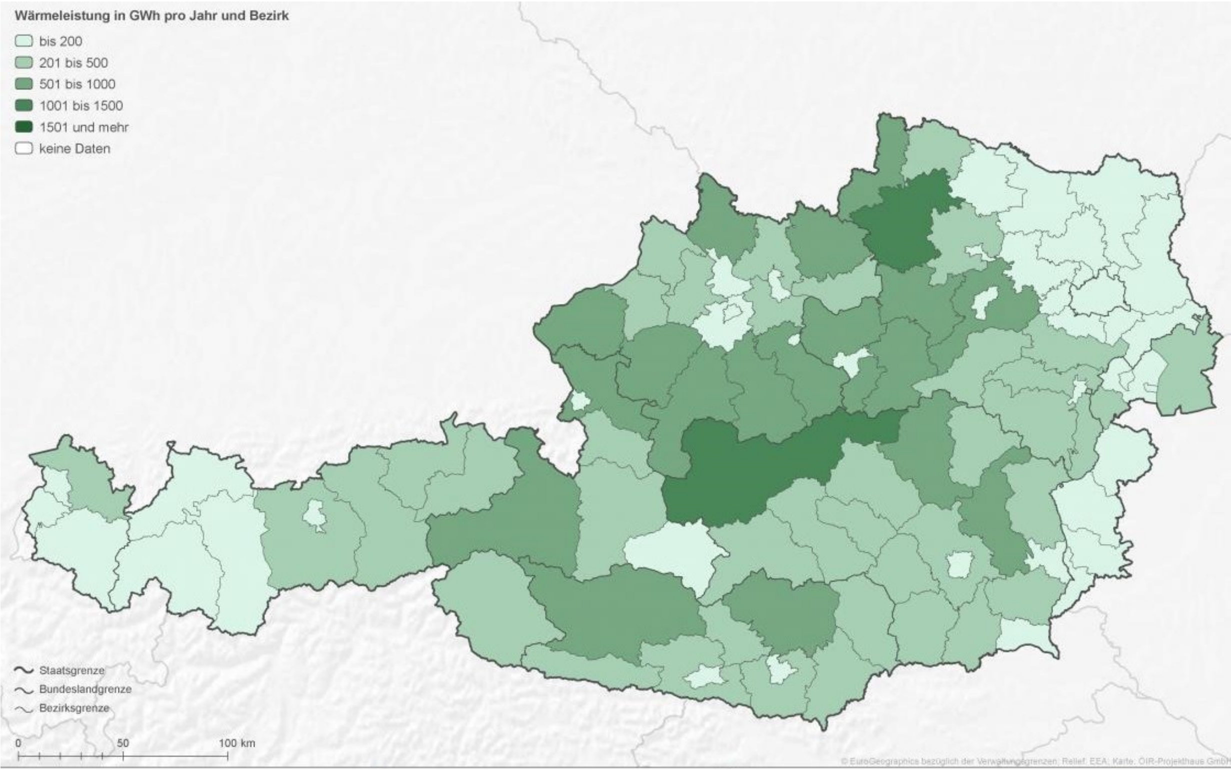


Figure 4-20: Biomass potential in the forestry sector (source: Regio Energy project, Stanzer et al., 2010)

Wärmeleistung in GWh pro Jahr und Bezirk	Heat output in GWh per year and district
Bis	To
Und mehr	And over
Keine Daten	No data
Staatsgrenze	National border
Bundeslandgrenze	Federal state border
Bezirksgrenze	District border

4.7 Technical potential for geothermal and ambient heat

4.7.1 Use of deep geothermal energy

The potential for deep geothermal energy is calculated on the basis of the study by Könighofer et al. (2014). This study pinpoints all municipalities across the whole of Austria with the potential for feeding geothermal energy into a district heating grid under certain conditions. To determine technical potential, the minimum criteria specified by the study are applied to all 44 municipalities with geothermal potential for 2020, as demonstrated in Figure 4-21. The basic conditions to be met are specified as a drilling depth of between 2000 m and 6000 m, and a minimum output of 10 MW with a bulk quantity of 70 l/sec. For the primary regions, estimates were made using the usage potential for the various potential regions as shown in Figure 4-22, which were then aligned in collaboration with the authors of the Könighofer et al. (2014) study. All municipalities with geothermal potential classified as secondary regions demonstrate a technical potential of 30 GWh/a from geothermal if full-load hours are assumed to stand at 3000 h/a. In the case of municipalities partially falling within a primary region, the geothermal potential is instead allocated to the primary region, and the remaining part of the municipality classed as a secondary region is not indicated has having any geothermal potential. In total, this results in a geothermal potential in Austria of almost 1.9 TWh of energy suitable for feeding into district heating grids.

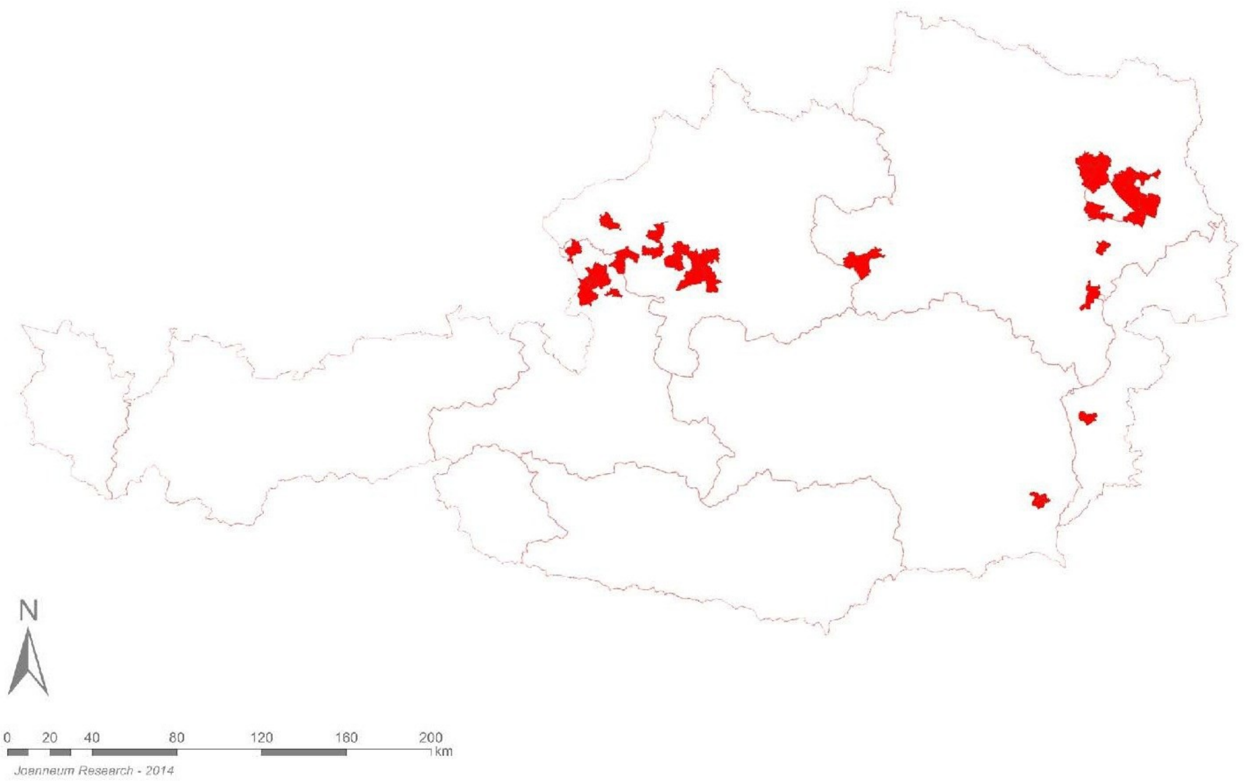


Figure 4-21: Map of geothermal potential indicating all municipalities that meet the basic requirements for use of geothermal energy in district heating systems (source: GeoEnergy2050 project, Könighofer et al., 2014)

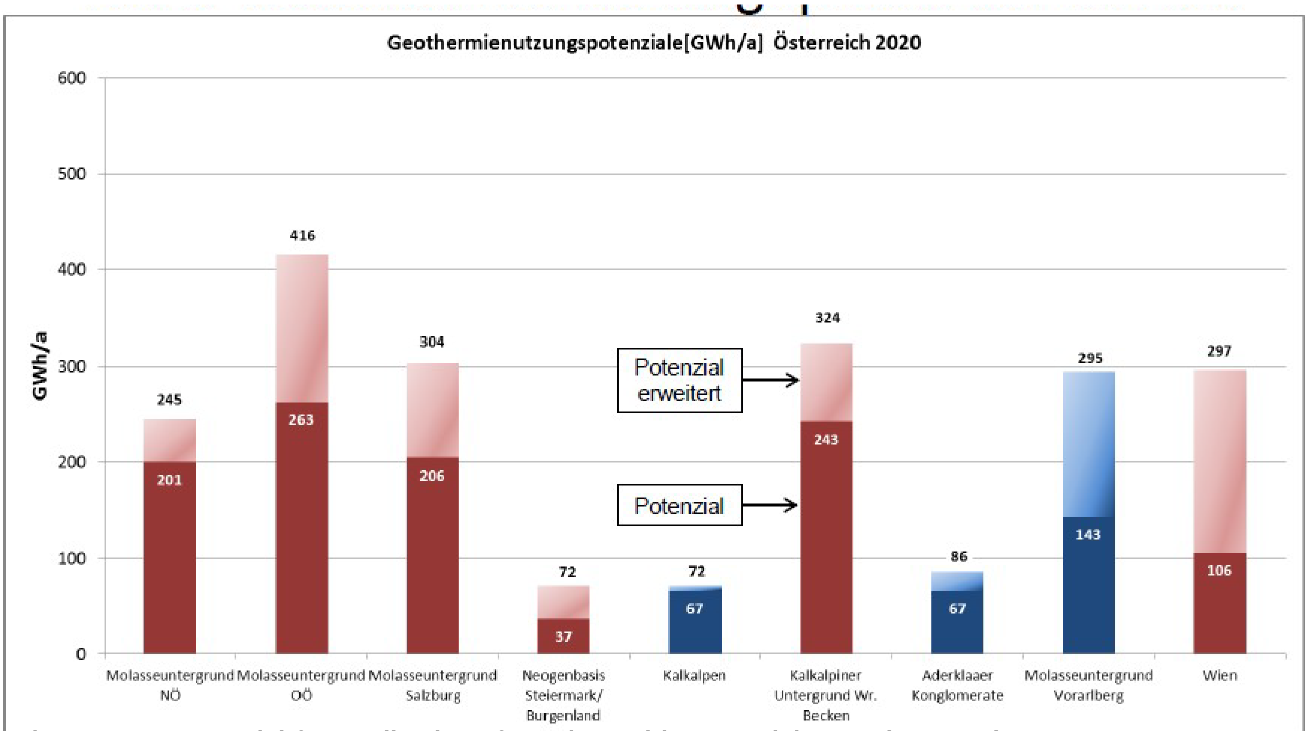


Figure 4-22: Potential for application of geothermal in potential areas in 2020 (source: GeoEnergy2050 project, Könighofer et al., 2014)

Geothermienutzungspotenziale [GWh/a] Österreich 2020	Potential for usage of geothermal [GWh/a] Austria 2020
Potenzial erweitert	Expanded potential
Potenzial	Potential
Molasseuntergrund Nö	Molasse bedrock Lower Austria
Oö	Upper Austria
Neogenbasis Steiermark/Burgenland	Neogene foundation Styria/Burgenland
Kalkalpen	Limestone Alps
Kalkalpiner Untergrund Wr. Becken	Limestone Alps, Vienna Basin bedrock
Aderklaaer Konglomerate	Aderklaa Conglomerate
Wien	Vienna

4.7.2 Use of heat pumps and high capacity heat pumps

The technical potential for near-surface geothermal energy is calculated on the basis of the results from the GEO-Pot study (Ostermann et al., 2010). In this study, the potential capacity of near-surface geothermal energy (combination of geothermal probes and heat pumps) to cover heat demand was analysed using GIS-based methods. The number of residential areas whose heat demand could be fully covered by near-surface geothermal energy depends largely on the assumptions made regarding the deep probes required (see Ostermann et al., p. 131f). In what is regarded as a 'realistic' scenario, it is assumed that the majority of residential areas have a surplus supply of thermal energy, with the exception of city centres. There may also be potential for air/water heat pumps, but these were not investigated in this study. On the basis of these results, the technical potential for building-related supply is initially regarded as unrestricted. The only restriction to technical potential is the total heat demand from all areas not connected to district heating grids.

Alongside decentralised, building-related heat pumps, certain heat sources in combination with high capacity heat pumps appear to be a promising field for efficient heat supply in urban areas. These heat sources include: surface water, groundwater, waste water, tunnel constructions and heat recovered from district heating grids. High capacity heat pumps could then be designed to provide combined heating/cooling. A study conducted by Ochsner et al. (2013) calculated a theoretical potential for covering heat demand through use of waste water from sewage treatment plants of 0.4–0.6 million residential units in Austria on the basis of a bivalent operating mode (high capacity heat pumps operating at between one third and half of maximum heat capacity plus peak load boilers) (see Ochsner et al., 2013, p. 16). In a qualitative analysis of the feasibility of using geothermal energy from tunnel constructions conducted by Ostermann et al. (2010), 22 of the 44 projects analysed emerged as suitable heat sources. However, the study does point out that extrapolations to calculate this potential for the whole of Austria would not be particularly useful due to the individual conditions at each site (elimination of potential heat consumers including on-site use, possible connection capacity, need to prevent formation of ice). Individual studies and own calculations also indicate relevant theoretical potential in the use of surface water. However, it was not possible to quantify this technical potential in this project, as no comprehensive data on heat sources is available.

In any case, it is assumed that overall there is major technical potential to be found in the use of a range of heat sources in combination with heat pumps. It should be noted, however, that the use of a large quantity of heat pumps to supply individual buildings may have a significant impact on the electricity sector. On the one hand, the increase in demand for electricity would cause electricity prices to rise, and if this was concurrent with a rise in demand for heat, the cost-effectiveness of using heat pumps to supply heat without the possibility to shift loads would be impaired. On the other hand, a large number of heat pumps would likely lead to an increase in peak electricity loads, which should be regarded as a negative consequence both from the perspective of the electricity grids themselves and in light of the generation capacity this would require. Below is a rough estimation of the maximum concurrent heat load ($P_{th,max}$) for the whole of Austria, which comes out as 28 GW.

On the basis of assumptions regarding the proportion of this load that could be covered by heat pumps (α) and the proportion of this maximum heat load that would occur at peak load times in the electricity grid (θ) as well as an average performance coefficient for the heat pumps (ε_{WP}), taken here as 3, an increase in peak electricity load is brought about (P_{el}^{+}).

$$P_{el}^{+} = \frac{P_{th,\max} \cdot \alpha}{\varepsilon_{WP}} \cdot \theta$$

If the entirety of this heat load were covered by heat pumps and if this load were fully concurrent with the original peak load in the electricity grid, this would lead to an increase in the peak electricity load of more than 9 GW, which is equivalent to almost twice the current peak load. Although this is certainly a worst-case-scenario, given the existence of certain smoothing factors (concurrence of total heat demand, concurrence with electricity demand, management systems for the heat pumps), it is highly likely that high penetration would result in major increases in peak loads in the electricity system. An appropriate quantity of heat pumps used for decentralised heat supply could be calculated on the basis of economic considerations weighing up electricity generation costs (taking particular account of the costs of covering peak electricity loads) and the costs of alternative forms of heat provision. This would require a more thorough analysis of developments in the electricity system, which was not possible in the context of this project.

As regards the application of high capacity heat pumps in district heating grids, the effect this would have on peak electricity load varies depending on the scenario. If high capacity heat pumps were used complementary to existing provision technologies so that they would not have to be used to cover peak heat loads, the use of heat pumps in district heating grids would not necessarily lead to an increase in peak electricity loads. In this case, the use of the heat pumps would depend on electricity prices, and would ultimately have a positive impact on the electricity system (use of surplus electricity, provision of control power etc.) and would result in increased flexibility in supplying district heating. The cost-effectiveness of this solution essentially depends on developments on the electricity market (in particular as regards the feed-in of PV and wind energy) and investment costs for the individual projects, especially in terms of exploitation of the heat sources.

4.8 Technical potential for waste incineration

The potential for using waste heat from waste incineration plants was only calculated for the primary regions, as the existing facilities are mostly located within range of these urban areas. Potential was calculated on the basis of facilities currently operated by energy companies and municipal providers. Given existing capacity, it is assumed that there is no further potential for constructing new waste incineration plants in Austria. One of the difficulties in determining the potential for feeding this energy into a district heating grid is that some of the existing facilities use the heat generated for other purposes, meaning that it is not possible to assess how this heat is primarily intended to be used. Industrial co-incineration of waste falls under industrial waste heat and not waste incineration.

The technical potential for feeding heat generated through municipal waste incineration into district heating grids stands at 2 TWH/a.

4.9 Technical potential for solar thermal energy

In the case of solar thermal systems, the building surface area potential was calculated. To do so, an analysis was conducted of roofs suitable for installation of solar thermal systems on the basis of publicly available solar land registers, although it was only possible to access pre-prepared GIS maps rather than the primary data. On the basis of these analyses, the average percentage of roofs (for buildings mapped in the Invert/EE-Lab model) suitable for solar energy production was estimated at approx. 50 % for small buildings and approx. 85 % for large buildings. The increase in the percentage for large buildings is primarily a result of the fact that these buildings usually have a flat roof. This means that a much smaller area of the roof is angled away from the direction of the light. However, with flat roofs it would still be necessary to maintain a gap between rows to avoid shading, as with free-standing systems. As such, an additional utilisation rate restriction of 1 m² of panel surface per 2.5 m² of roof area is applied. The percentage of buildings fundamentally suitable for installation of solar panels was estimated at 90 % in rural areas and in city suburbs, with a lower percentage of approximately 65 % estimated for core areas in city centres (above all due to restrictions in relation to the preservation of attractive townscapes). Large buildings such as residential apartment blocks containing more than 10 residential units and large services buildings account for around 40 % of the potential surface area, and are estimated to have a potential average annual yield of 400 kWh/m² in terms of technical potential for feeding solar thermal power into district heating grids. On the basis of the roof surface area potential for smaller buildings, average annual yield is estimated at 350 kWh/m², which is then used to calculate the technical potential for decentralised solar thermal energy. Some observations on the sizes of storage facility required are discussed below. Figure 4-23 presents the technical potential for feed-in to a district heating grid and for decentralised supply in the primary regions.

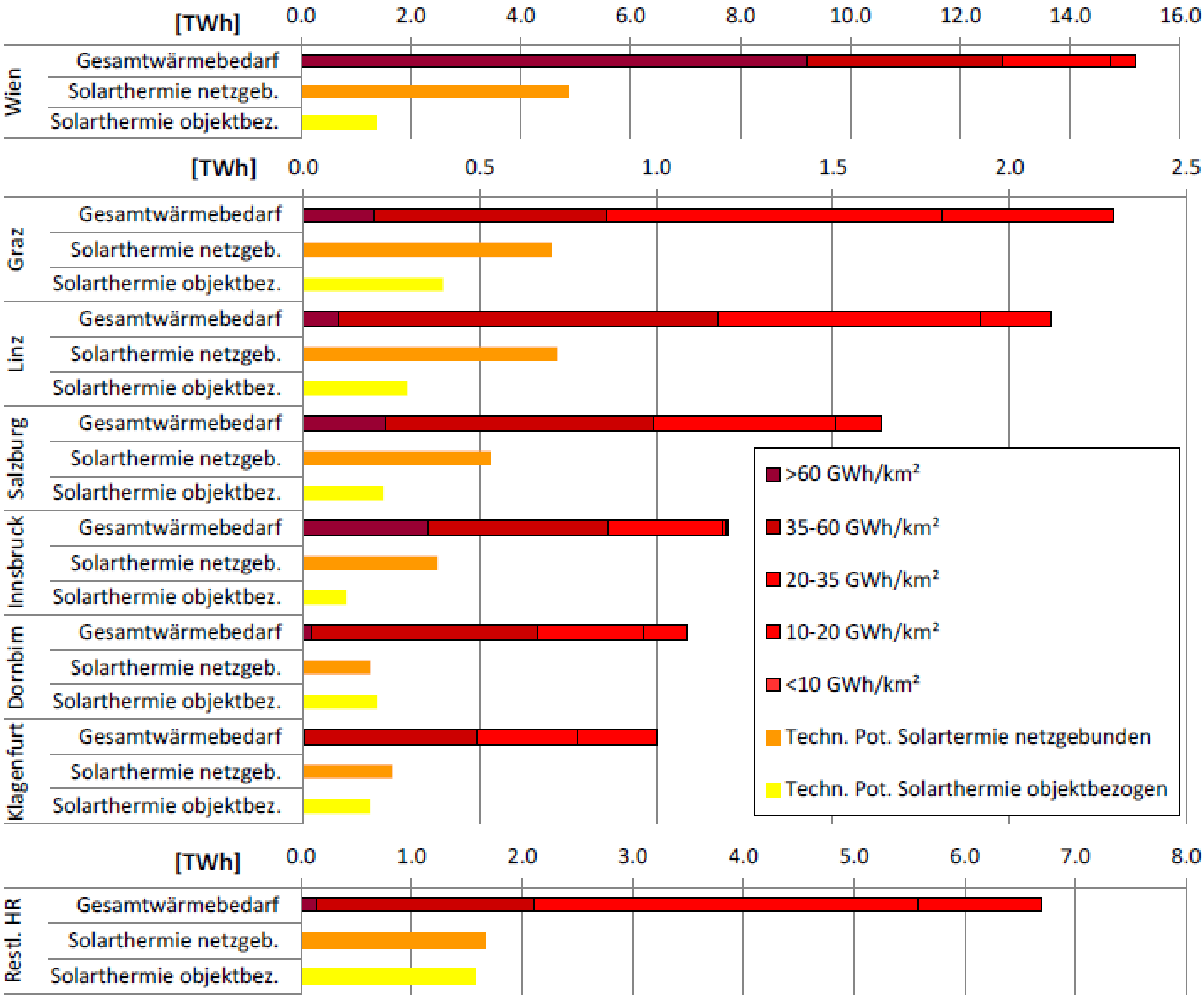


Figure 4-23: Heat demand and technical potential for application of solar thermal energy for both grid-bound and building-related supply in the key primary regions and aggregated for the remaining regions

Wien	Vienna
Gesamtwärmebedarf	Total heat demand
Solarthermie netzgeb.	Grid-bound solar thermal
Solarthermie objektbez.	Building-related solar thermal
Restl. HR	Remaining primary regions
Techn. Pot. Solarthermie netzgebunden	Technical potential for grid-bound solar thermal
Techn. Pot. Solarthermie objektbezogen	Technical potential for building-related solar thermal

The hereby calculated technical potential in the primary regions amounts to 13.7 TWh, of which 9.3 TWh could be generated from buildings designated as 'large buildings' and would therefore be suitable for feeding into a district heating grid, and 4.4 TWh from small buildings that would thus be more suitable for covering the heat demand of individual buildings. For all secondary regions, potential stands at 24 TWh, of which 5.7 TWh could be generated from large buildings and 18.6 TWh from small buildings.

It should be borne in mind that the potential values given here were calculated on the basis of potential annual yields of 400 kWh/m² and 350 kWh/m² respectively. In order to effectively achieve these yields, solar thermal systems would usually have to be run in combination with a storage system, as heat demand and supply times do not necessarily coincide. Figure 4-24 illustrates this correlation. By way of example, the load profile for a district heating grid is also indicated, as is the solar thermal capacity that would arise if the technical potential were fully exploited. Different quantities of energy could be fed into the grid depending on the combination of storage system capacity and module size. If a district heating system is already equipped with base load feeders (waste incineration, waste heat) that generate heat all year round, the amount of solar thermal energy that could be integrated falls further.

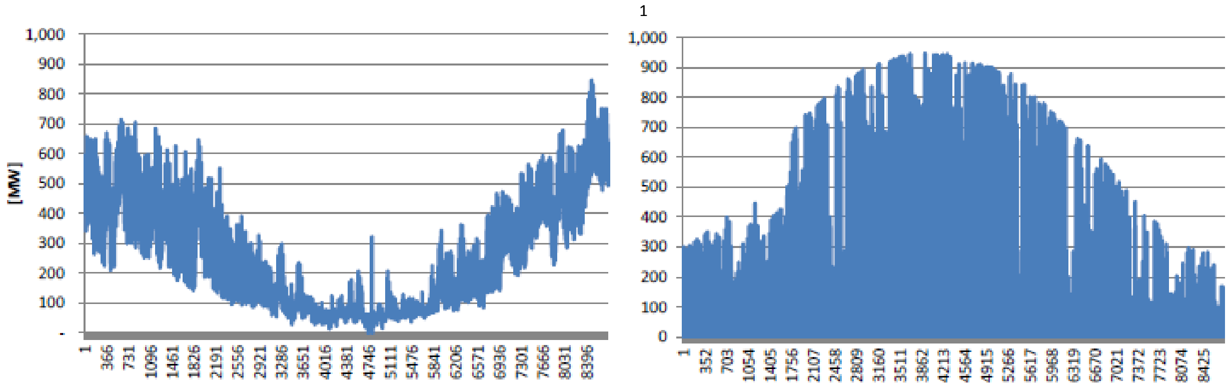
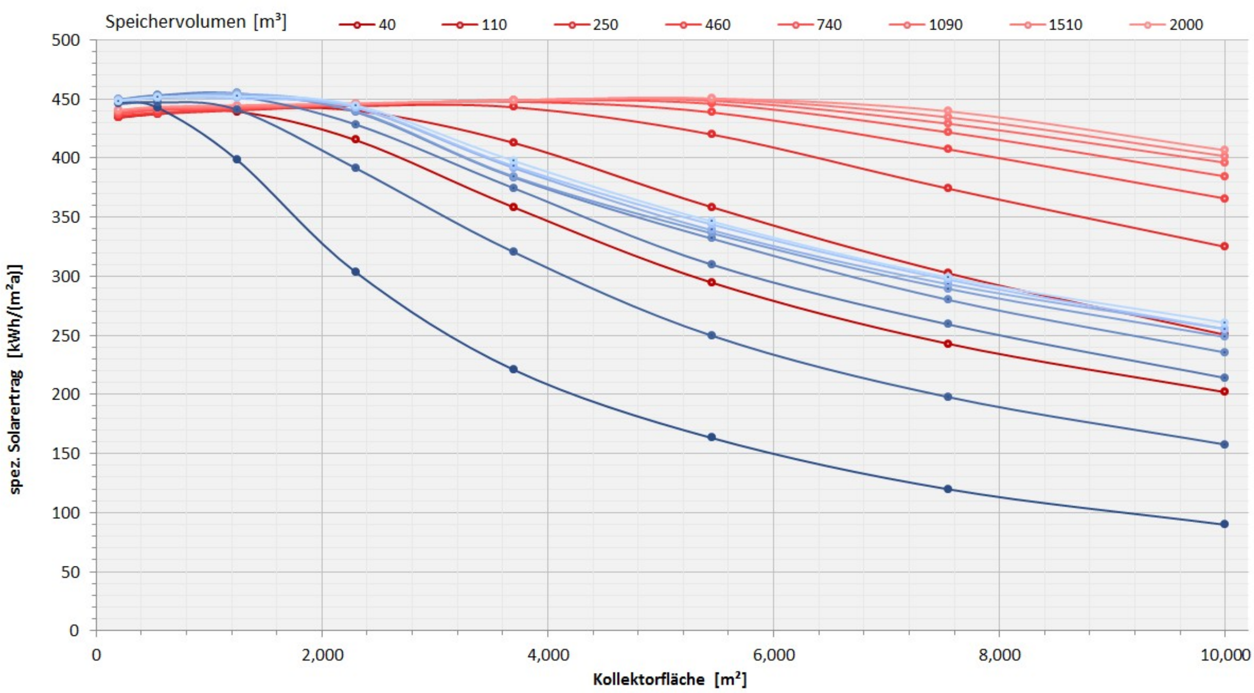


Figure 4-24: Heat load curve of a district heating system and accompanying delivery profile of a solar thermal system in the event of full exploitation of the technical potential

The figures below demonstrate, on the basis of exemplary heating grid types, that the specific solar energy yield decreases to varying degrees depending on the solar coverage rate and the storage capacity. However, if the storage systems were sized accordingly, values of around 400 kWh/m²/a could be achieved, even at higher coverage rates.



Speichervolumen	Storage volume
Spez. Solarertrag	Specific solar energy yield
Kollektorfläche	Panel area

Figure 4-25: Specific solar energy yield depending on panel area and storage capacity for two different-sized heating grids. Red: urban sub-grid with high heat demand. Blue: rural heating grid with low heat demand. Source: Solar Grids Tool (Müller et al., 2014)

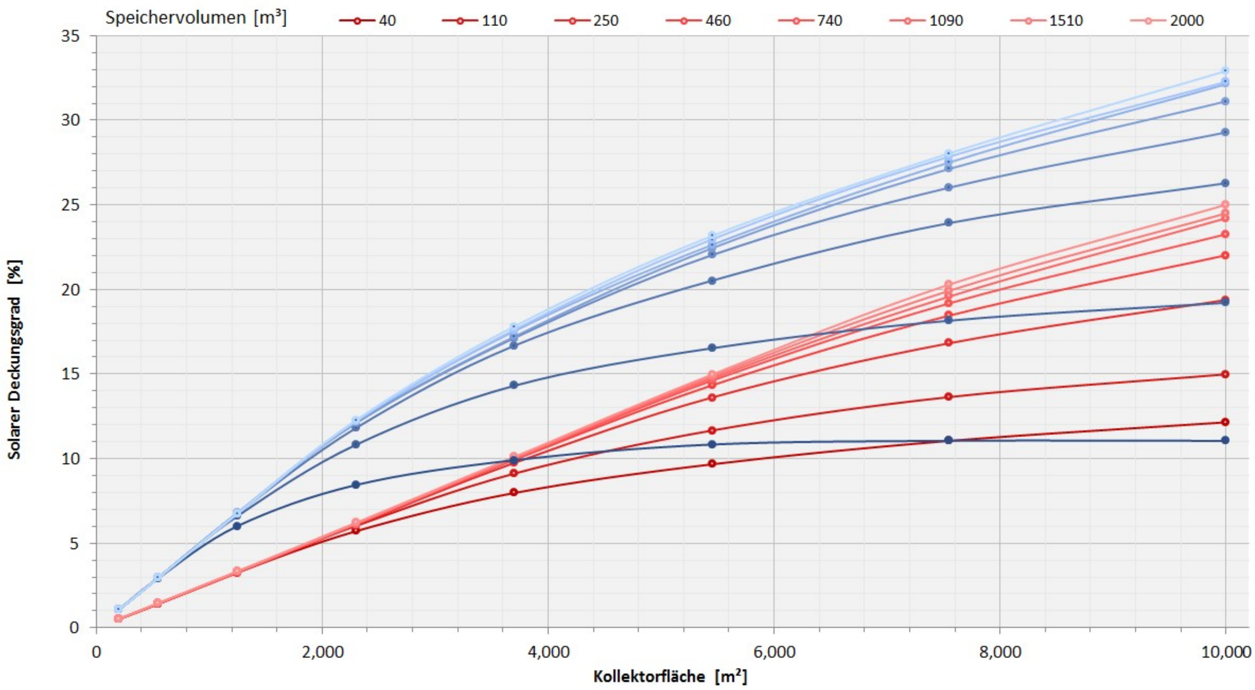


Figure 4-26: Solar coverage rate depending on panel area and storage capacity for two different-sized heating grids. Red: urban sub-grid with high heat demand. Blue: rural heating grid with low heat demand. Source: Solar Grids Tool (Müller et al., 2014)

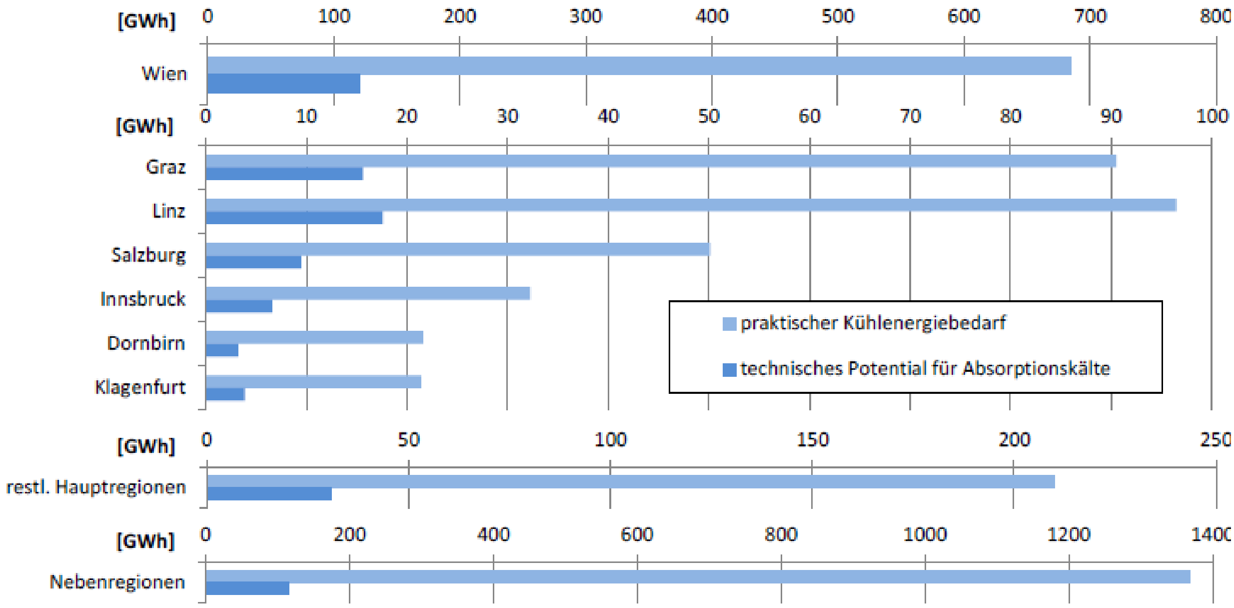
Speichervolumen	Storage volume
Solarer Deckungsgrad	Solar coverage rate
Kollektorfläche	Panel area

4.10 Technical potential for efficient cooling

The technical potential for cooling technologies is determined based on model calculations carried out using the Invert/EE-Lab model. The model first calculates cooling demand in buildings (useful energy demand) under the assumption that all buildings are equipped with air conditioning systems. However, in reality, it will not be possible to cover all useful energy demand since many private households do not have air conditioning systems installed. Therefore, diffusion restrictions are subsequently introduced into the model for the number of air-conditioned buildings. In order to maintain consistency, the assumptions for these diffusion restrictions were taken from the project 'Establishment of energy input parameters and scenarios in order to meet the reporting obligations of the monitoring mechanism' (Müller and Kranzl, 2013). The resulting end energy consumption for air conditioning purposes in Austria stood at approximately 500 GWh in 2012, and is estimated to rise to 858 GWh by 2025. On the basis of an average performance coefficient for air conditioning systems of 3, this results in a useful energy demand of 2.6 TWh in practice for the year 2025.

A further restriction is then applied to the technical potential of absorption chillers. As chillers are only likely to be installed in buildings with high cooling loads and full-load hours of around 1000 h/a, an attempt is made to estimate this share of cooling energy demand. For the following building categories: retail, hotel, public buildings (health sector, partially office-occupied, education sector) and offices, the share of cooling energy demand accounted for by buildings classed as 'large' is calculated, and a fixed proportion of 80 % of these are regarded as suitable for installation of absorption chillers. In the retail sector, 37 % of cooling demand is accounted for by buildings likely to attain a large number of full-load hours, in the hotel sector 38 %, in public buildings 32 % and in office buildings 56 %. In addition, it is assumed that peak loads can be covered by compression chillers.

Figure 4-27 illustrates the practical energy demand for cooling buildings in 2025, and the share of this accounted for by buildings likely to have absorption chillers installed. In the whole of Austria, this equates to a practical cooling energy demand of around 2.6 TWh and a technical potential for absorption chillers of a little over 0.3 TWh.



Restl. Hauptregionen	Remaining primary regions
Nebenregionen	Secondary regions
Praktischer Kühlenenergiebedarf	Practical cooling energy demand
Technisches Potential für Absorptionskälte	Technical potential for absorption chillers

Figure 4-27: Practical cooling energy demand for cooling buildings and technical potential for absorption chillers in the key primary regions and aggregated for the remaining regions

5 Cogeneration efficiency criterion and potential for efficiency gains

The following section discusses the efficiency criterion for high-efficiency cogeneration and the impact of the technical design of cogeneration plants on meeting efficiency requirements. Subsequently, measures to increase the efficiency of cogeneration plants and heating grids by reducing flue gas temperatures in cogeneration plants and return flow temperatures in heating grids are analysed. It was not possible to quantify the potential for efficiency gains throughout Austria in the context of this study, as the data available on the effective mode of operation of the plants and heating grids is very poor. As such, the measures portrayed here could not be included in the economic analysis in Section 6.

5.1 Assessment criteria

Both Directive 2012/27/EU on energy efficiency and its implementing decisions (Equation 5-1) and the Austrian Cogeneration Act [KWK-Gesetz] of 27/02/2014, Part 2, Section 8 (Equation 5-2) provide criteria for assessing the efficiency of cogeneration plants (see also Section 4.1).

$$PES = \left(1 - \frac{1}{\frac{\eta_W}{\eta_{refW}} + \frac{\eta_E}{\eta_{refE}}}\right) 100 \geq 10$$

Equation 5-1

$$\frac{2}{3}\frac{W}{B} + \frac{E}{B} > 0{,}6$$

Equation 5-2

In Equation 5-1, in line with the aforementioned Directive, PES denotes primary energy savings, η_W denotes the heat efficiency of the cogeneration production defined as annual useful heat output divided by the fuel input used to produce the sum of useful heat output and electricity from cogeneration, η_{refW} the efficiency reference value for separate heat production, η_E the electrical efficiency of the cogeneration production defined as annual electricity from cogeneration divided by the fuel input used to produce the sum of useful heat output and electricity from cogeneration and η_{refE} the efficiency reference value for separate electricity production. The harmonised efficiency reference values for separate production of electricity and for separate production of heat are published in the Official Journal of the European Union (L 343/93).

In Equation 5-2, W denotes the heat energy supplied to the public district heating grid or used economically as process heat, B the total fuel energy used and E the electrical energy supplied to the public electricity grid or measured at the generator terminal.

If primary energy savings (PES) of greater than 10 % are calculated using Equation 5-1, the system in question may be regarded as a high efficiency system. If a system does not achieve PES of 10 %, the difference can be regarded as technical potential for efficiency gains.

According to the Directive, electricity production from small-scale and micro-cogeneration units providing primary energy savings may qualify as high-efficiency cogeneration.

Whereas under the EU Directive, the efficiency values for separate heat and electricity production are compared with reference values that take account of both fuel type and the age of the system, under the Austrian Cogeneration Act only electricity produced, heat extracted and fuel used are set against one another. As such, it is clear that plants using lower quality fuel will be at a disadvantage.

5.2 Application of the criteria to different types of cogeneration

In Austria, the primary types of cogeneration systems operated are the following:

- steam power process
- with back-pressure turbine
- with extraction-condensing turbine
- gas power process with heat recovery
- CHP plants (gas or diesel engine with heat recovery)

The contribution of each of the cogeneration types to meeting the high-efficiency criterion is described below by way of illustration through a comparison of steam power processes with back-pressure turbines and extraction-condensing turbines.

If heat is extracted from steam power processes fuelled using lower grade fuels (e.g. industrial waste instead of natural gas), that should generally be acknowledged.

As demonstrated in Figure 5-1, in steam power facilities with a back-pressure turbine, the overheated steam in steam turbines is brought down to a pressure with a saturated steam temperature that corresponds to the desired temperature of the heat to be extracted. The heat is released during condensation between statuses 3 and 0. The heat flow is proportional to the area outlined in red in the T-s diagram in Figure 5-1 multiplied by the steam mass flow.

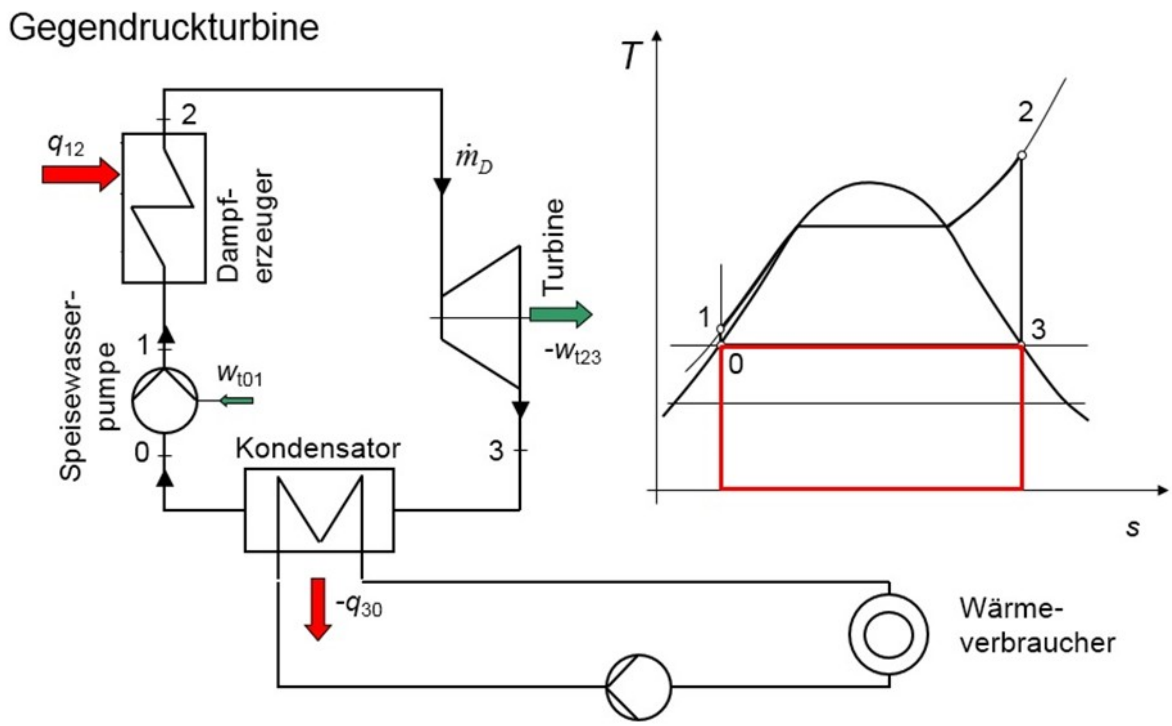


Figure 5-1: Schematic and T-s diagram of a simple steam power plant with back-pressure turbine

Gegendruckturbine	Back-pressure turbine
Turbine	Turbine
Speisewasserpumpe	Feed water pump
Kondensator	Condenser
Wärmeverbraucher	Heat consumer

As demonstrated by the example calculation below, the efficiency criteria are easier to comply with for this type of process than for steam power plants with extraction-condensing turbines.

On the basis of the typical baseline values for a simple steam power process as listed in Table 5-1, the following result is obtained for a back-pressure turbine after several calculation steps and upon application of Equation 5-3 whereby Q_{NG} denotes the extracted heat, h_2 - h_3 the enthalpy difference between the turbine inlet and outlet and thus the electrical energy, h_2 - h_{1K} the enthalpy difference for the supplied heat and η_{DE} the efficiency of the steam generator.

$$\frac{2}{3}\frac{Q_{NG}}{\left(\frac{h_2 - h_{1K}}{\eta_{DE}}\right)} + \frac{h_2 - h_3}{\left(\frac{h_2 - h_{1K}}{\eta_{DE}}\right)} = 0{,}68277 > 0{,}6$$

Equation 5-3

As such, the efficiency criterion would be met on the basis of these assumptions.

Table 5-1: Typical baseline values for a simple steam power process

Parameter	**Formula symbol**	**Baseline value**

Steam inlet temperature:	Θ_2	540°C
Steam generator pressure:	p_D	150 bar
Back pressure (pressure in the heat extraction condenser):	p_G	1 bar
Condenser pressure (pressure in waste heat condenser):	p_K	0.05 bar

In the case of power steam processes with extraction-condensing turbines (see Figure 5-2), the turbine is tapped once it reaches a pressure at which the saturated steam temperature corresponds to the desired heat extraction temperature. The extracted steam mass flow is condensed in a heat condenser, resulting in an extracted heat flow (area outlined in red on the T-s diagram in Figure 5-2 multiplied by the corresponding mass flow). The remaining steam is brought down to the condenser pressure (status point 3) of the turbine. This must be condensed in the condenser (status change 3 to 0) in order to complete the cycle. The energy generated in the condenser has to be dissipated into the environment via a heat exchanger, whereby the difference in temperature compared to the ambient temperature must be as low as possible.

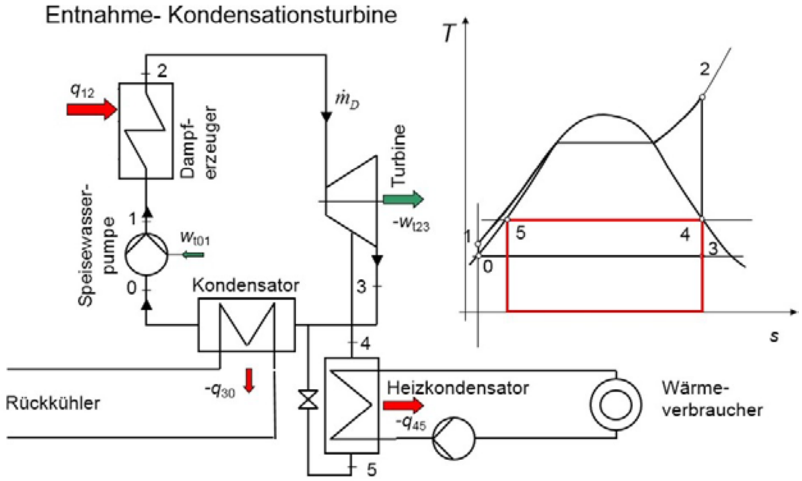


Figure 5-2: Schematic and T-s diagram for a steam power plant with extraction-condensing turbine

Entnahme- Kondensationsturbine	Extraction-condensing turbine
Dampferzeuger	Steam generator
Speisewasser-pumpe	Feed water pump
Kondensator	Condenser
Rückkühler	Heat exchanger
Heizkondensator	Heat condenser
Wärmeverbraucher	Heat consumer

Using the same baseline values as above, the high-efficiency criterion can only be met once a certain amount of steam is extracted. In accordance with the Cogeneration Act, efficiency rises in a linear fashion as the amount of steam extracted grows, breaching the high-efficiency threshold upwards of roughly 0.7. In the event of 70 % extraction, using Equation 5-2, the following is obtained:

$$\frac{2}{3}\frac{Q_{NE}}{\left(\frac{h_2-h_{1K}}{\eta_{DE}}\right)}+\frac{h_2-h_3+(h_3-h_5)\cdot(1-\varepsilon_D)}{\left(\frac{h_2-h_{1K}}{\eta_{DE}}\right)}=0{,}6033>0{,}6$$

Equation 5-4

whereby Q_{NE} denotes the extracted heat, $(h_2 - h_3) + (h_3 - h_5)\cdot(1 - \varepsilon_D)$ the enthalpy difference for the proportion converted into electricity, $h_2 - h_{1K}$ the enthalpy difference for the supplied heat, η_{DE} the steam generator efficiency rate and ε_D the amount of steam extracted.

This means that although cogeneration using an extraction-condensing turbine is able to supply heat and electricity in a more flexible manner, it does need to be powered to a large extent by extracted heat in order to meet the high-efficiency criterion. Any increases in condenser temperatures (e.g. through the build-up of non-condensable gases) have only a negligible effect here. If high-grade fuel is available to power a cogeneration facility (e.g. natural gas), a good option is a gas power process with downstream heat recovery (see Figure 5-3). With this type of plant, electrical energy is produced via the gas power process, whereby the thermal energy in the exhaust gases generated above temperatures of 450°C can be used in an exhaust gas heat exchanger. In the exhaust gas heat exchanger, thermal energy at temperatures of up to 200°C and steam at pressures of up to 80 bar is available for heat extraction. This type of system can be electricity- or heat-controlled.

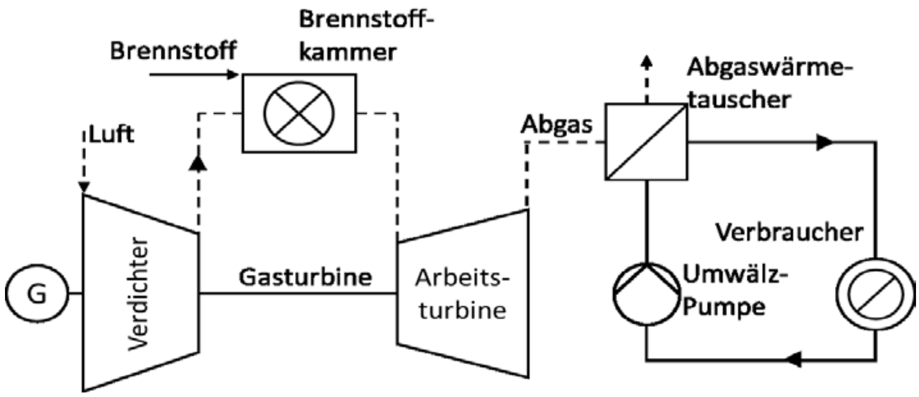


Figure 5-3: Schematic of a cogeneration system with gas turbine and exhaust gas recovery

Brennstoff	Fuel
Brennstoffkammer	Fuel chamber
Luft	Air
Verdichter	Compressor
Gasturbine	Gas turbine
Arbeitsturbine	Power turbine
Abgas	Exhaust gas
Abgaswärmetauscher	Exhaust gas heat exchanger
Verbraucher	Consumer
Umwälzpumpe	Circulation pump

As for decentralised supply and lower capacity bands (up to several megawatts), CHP plants are a good option (see Figure 5-4). In this type of facility, total utilisation rates of up to 85 % can be attained. Natural gas is normally used as a fuel, but gases from waste water plants and landfill deposits can also be used. Inlet temperatures of up to 110°C can usually be achieved in CHP plants. The operating mode of CHP plants can be electricity- or heat-controlled.

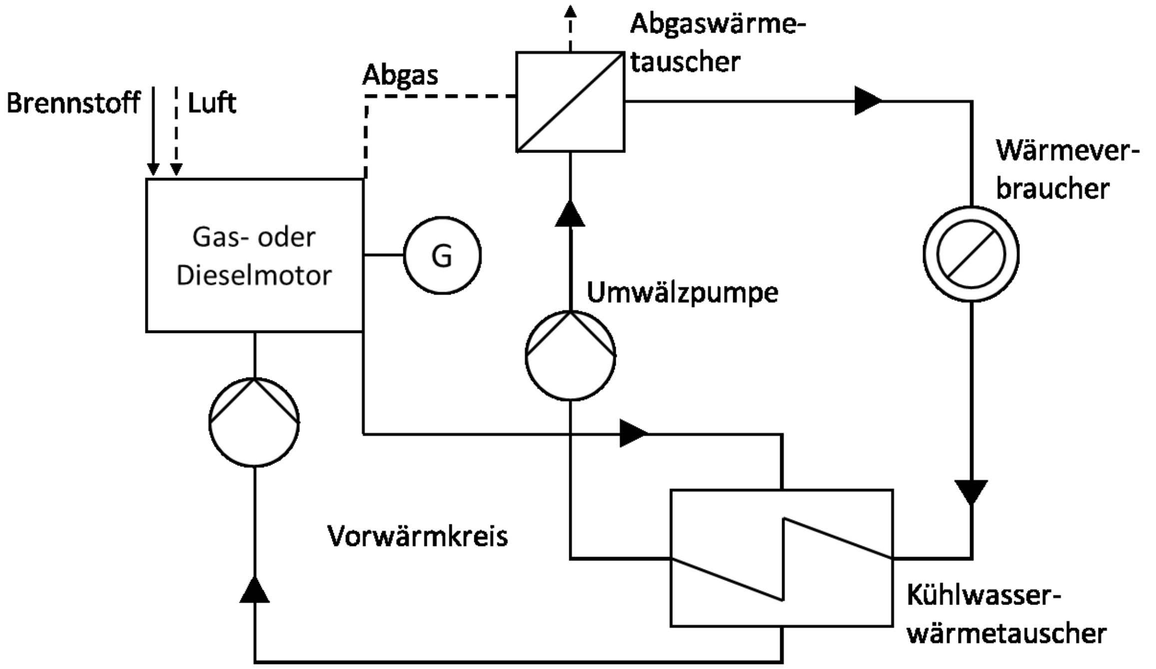


Figure 5-4: Schematic of a CHP plant

Brennstoff	Fuel
Luft	Air
Abgas	Exhaust gas
Abgaswärmetauscher	Exhaust gas heat exchanger
Gas- oder Dieselmotor	Gas or diesel engine
Wärmeverbraucher	Heat consumer
Vorwärmkreis	Pre-heating circuit
Kühlwasserwärmetauscher	Cooling water heat exchanger

5.3 Measures to increase efficiency

5.3.1 Cogeneration

The efficiency of a cogeneration system depends largely on keeping exhaust gas temperatures as low as possible. In CHP plants with steam power processes, this has a direct effect on steam generator efficiency, for which a calculation method is stipulated in the ÖNORM EN 12952-15 standard.

In order to illustrate the effect of this, Equation 5-5 calculates the efficiency criterion for a steam power system with a back-pressure turbine (Figure 5-1) in the event of a 5 % decrease in steam generator efficiency (η_{DE} = 0.9) but with all other baseline values unchanged.

Equation 5-5

$$\frac{2}{3}\frac{Q_{NG}}{\left(\frac{h_2-h_{1K}}{\eta_{DE}}\right)}+\frac{h_2-h_3}{\left(\frac{h_2-h_{1K}}{\eta_{DE}}\right)}=0{,}64683>0{,}6$$

Although the criterion is still met, the value is much closer to reaching the inequality threshold.

In order to still meet the efficiency criterion in a steam power system with an extraction-condensing turbine (Figure 5-2) at a steam generator efficiency rate of η_{DE} = 0.9 and with all other conditions unchanged, the volume of extracted steam ε_D must be increased to approx. 85 % (Equation 5-6).

Equation 5-6

$$\varepsilon_D = 0{,}85$$

$$\frac{2}{3}\frac{Q_{NE}}{\left(\frac{h_2 - h_{1K}}{\eta_{DE}}\right)} + \frac{h_2 - h_3 + (h_3 - h_5)\cdot(1-\varepsilon_D)}{\left(\frac{h_2 - h_{1K}}{\eta_{DE}}\right)} = 0{,}60919 > 0{,}6$$

There is certainly potential to be found in reducing exhaust gas temperatures in CHP plants, but this potential is limited by inadequate fuel quality (risk of condensation of corrosive substances on the cold heating surfaces) and high return flow temperatures for the extracted heat.

Figure 5-5 presents steam generator efficiency rates in line with the calorific value (N) and fuel value (G) calculation under standard EN 12952-15 for use of natural gas as a fuel, with an air surplus of 10 % and a relative humidity of the combustion air of 40 % as a function of the exhaust gas temperature. Up until condensation of the first water droplets, which occurs at around 57°C under these conditions, an increase in the efficiency of useful heat supply of 0.4 percentage points can be achieved per 10°C reduction in exhaust gas temperature. Once condensation begins, an efficiency gain of as much as 4.5 percentage points per 10°C reduction in exhaust gas temperature can initially be achieved.

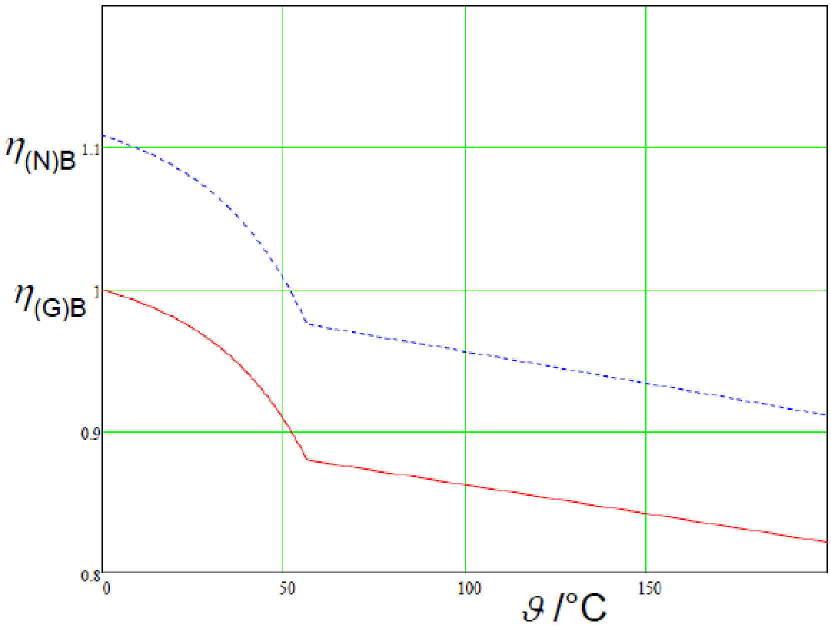


Figure 5-5: Efficiency levels in line with the calorific value (N) and fuel value (G) calculation for combustion of natural gas as a function of exhaust gas temperature

As mentioned, it would only be possible to exploit the potential indicated here at substantial cost. Partial use of the thermal energy released upon condensation of the condensable materials found in the flue gas (commonly referred to as flue gas condensation) would only be possible if particularly corrosion-resistant heat exchangers were used. Furthermore, this energy can only be exploited if the return flow temperatures of heat consumers are low enough. The use of heat pumps may present a partial remedy to this problem, but this would be associated with high investment and operating costs (electrical energy).

In the context of this study, examples of CHP plants run by four different companies from the paper, wood processing, steel and district heating sectors were analysed. In each case, related data sets regarding primary energy usage, electricity production and heat extraction were collected.

Of the companies investigated, it emerged that most have already taken measures to optimise their energy efficiency on several occasions, and there seem to be economic incentives for them to reduce their energy consumption or implement measures to increase efficiency. Very large, energy-intensive companies in particular are leading the way in this area.

Of the cogeneration plants studied, only one did not meet the high-efficiency criterion. This plant was equipped with a steam power system with an extraction-condensing turbine. The most commonly used fuel is waste from in-house production processes. Calculated in accordance with the Cogeneration Act (Equation 5-1), the technical potential for efficiency gains at this plant stands at 15 %, and at 3 % in accordance with the EU Energy Efficiency Directive.

5.3.2 District heating grids

Potential for efficiency gains in district heating grids in Austria can be found in possible reductions in grid return flow temperatures. These reductions could be achieved through consumer-side efficiency measures such as cascading heat usage and/or increased use of panel heating. The resulting savings in terms of the working hours of boilers and network pumps were calculated on the basis of the categorisation of Austrian district heating grids into three clusters as explained in Section 3.2.3. The basis for the calculation is a dynamic grid simulation model that simulates energy distribution performance across a district heating grid over a certain period (one year).

Using measurement data from representative heat consumers, the monthly required working hours for boilers and pumps were calculated and then totalled to obtain a yearly value. On the basis of a monthly floating inlet temperature, and assuming that primary-side water cooling is the same for each heat consumer (constant return flow temperature), an analysis was conducted to determine the quantitative effect of a hypothetical drop in return flow temperature on demand for boiler heat and pump electricity. If customer-side heat demand remains constant and the temperature spread stays high, the degree of water mass flow required for power transmission falls (Equation 5-7):

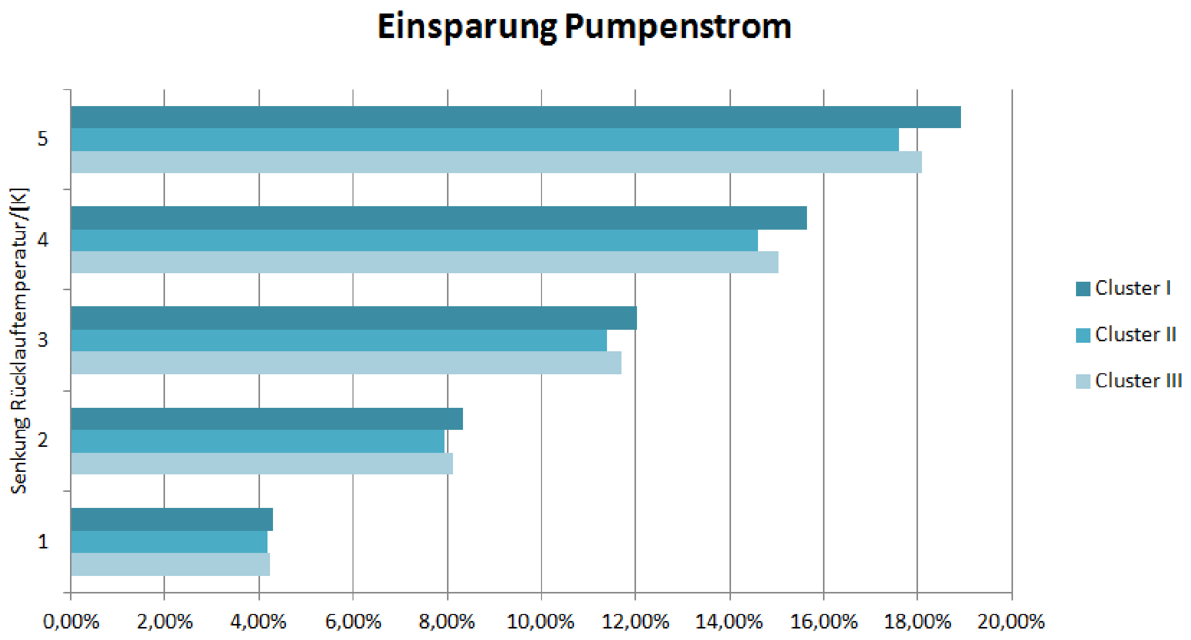
Equation 5-7

$$\dot{Q} = \dot{m}\, c_p\, (T_{VL} - T_{RL})$$

The drop in the water mass flow required in order to meet heat demand as a result of the wider temperature spread has a substantial effect on the pump capacity required. In addition, lower grid return flow temperatures enable flue gas condensation in heating plants, thereby helping to reduce primary energy demand in those plants.

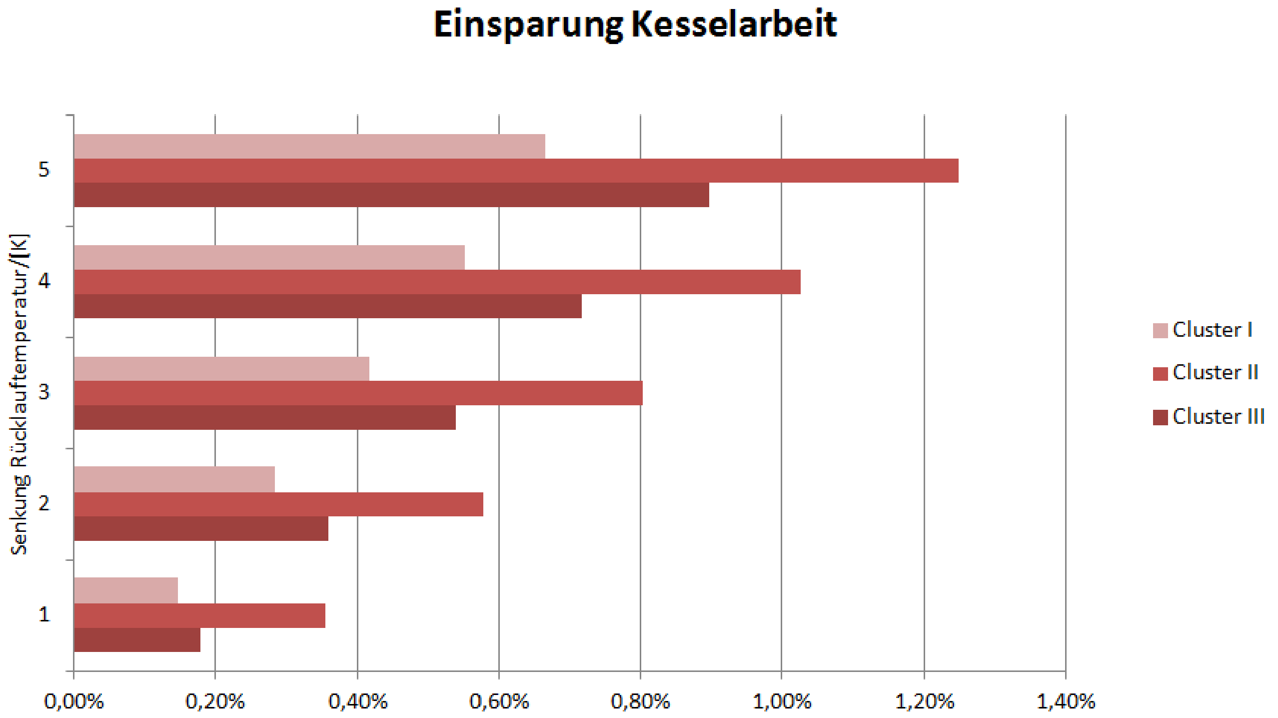
On the basis of the average values for the number of heat consumers, line length and annual heat distribution listed in Section 3.2.3, three district heating grids corresponding to Clusters I, II and III were simulated (reference case). Subsequently, the grids were simulated using return flow temperatures reduced by 1–5 K.

The following diagrams provide a quantitative indication of savings potential as a result of reducing the return flow temperature by 1–5 Kelvin compared to current operating levels:



Einsparung Pumpenstrom	Pump electricity savings
Senkung Rücklauftemperatur	Drop in return flow temperature
Cluster I	Cluster I

Figure 5-6: Reduction of the annual required pump output in relation to the reference case when reducing return flow temperatures by 1–5 Kelvin



Einsparung Kesselarbeit	Boiler output reduction
Senkung Rücklauftemperatur	Drop in return flow temperature
Cluster I	Cluster I

Figure 5-7: Reduction of the annual required boiler output in relation to the reference case when reducing return flow temperatures by 1–5 Kelvin

6 Cost-benefit analysis – economic potential

6.1 Introduction

According to the Energy Efficiency Directive, 'the purpose of preparing cost-benefit analyses in relation to measures for promoting efficiency in heat and cooling [...] is to provide a decision base for qualified prioritisation of limited resources at society level'.[12] In the cost-benefit analysis, this study attempts to identify the most cost-effective combination of technologies for heat and cooling and therefore the economic potential per technology for Austria in the year 2025. These technologies are analysed from an economic perspective.

As regards the technology mix for heating, a distinction is made between supply and demand in two temperature ranges: the 60–90°C range for households and businesses, and the 100–500°C range for the supply of steam to industrial consumers. The proportion of industrial heat that could be covered by district heating is very low due to the large losses arising in high temperature ranges, and is as such insignificant. Each temperature range is analysed separately.

For the households and businesses range, grid-bound heating and cooling options already in existence and likely to remain so until 2025 are analysed, taking into account their technical lifetimes. On this basis, residual demand is met using the most cost-effective technology in each case until the available technical potential (see Section 4) for the technology in question is fully exploited or until demand is covered. The technologies are selected depending on whether or not a district heating grid is available. As such, there is no one technology that is always the most cost-effective; in fact this varies depending on whether the region has a district heating grid or not, whether there is potential for expanding the grid, and whether there are limitations to the technical potential, e.g. in the case of solar thermal energy, geothermal, natural gas or industrial waste heat. Therefore, the economic potential of the technologies is analysed on the basis of the regional classification defined in Section 4.2.

The costs are composed of:

1. costs for the production of heat/cooling per technology, depending on the utilisation rate;
2. the costs of transmitting heat from the power station to the distribution grid as a result of the distance from district heating technologies (only relevant for certain technologies such as geothermal or waste heat);
3. distribution grid costs for supplying heat to end consumers for district heating technologies.

Benefits (income) only accrue to cogeneration plants.

Analyses are first carried out on the basis of a central scenario with the input parameters described in detail below. The central scenario is based on a grid connection rate for consumers not yet connected to district heating of 90 %, thereby representing the upper range of economic potential. Subsequently, in Section 6.8, sensitivity analyses are performed in order to investigate the influence of changes in some of the assumptions in more detail.

[12] Directive 2012/27/EU, Annex IX, Part 1.

6.2 Input parameters

6.2.1 Production costs

The technologies analysed and their input parameters in the housing and businesses area can be found in Table 6-1. When looking at the thermal efficiency rate, it should be borne in mind that grid-bound technologies incur network losses in the heating grid. These depend, inter alia, on inflow and return flow temperatures, the thermal insulation of the distribution lines and the size of the grid. For Austria, average network losses of 10 % are postulated.

Table 6-1: Overview of the technologies and parameters analysed for the housing and businesses area (source: see section 8.1)

Technology	Investment costs (EUR/kW$_{th}$)	Service life (a)	Operating/maintenance costs (EUR/kW$_{th}$*a)	Fuel/energy source	Thermal efficiency/COP	Electrical efficiency
Building-related technologies						
Air-conditioning systems	450	15	18.0	Electricity	2.4	0 %
Absorption chillers	1300	22	7.5	Electricity, district heating	10 (electricity), 0.7 (DH)	0 %
Boiler (natural gas)	255	20	9.8	Natural gas (households/businesses)	92 %	0 %
Boiler (biomass)	500	20	10.0	Biomass (pellets, households/businesses)	88 %	0 %
Boiler (electric)	80	20	5.3	Electricity (households/businesses)	100 %	0 %
Decentralised solar	1150	20	15.0	-	-	0 %
Local heat pump	1270	20	38.2	Electricity (households/businesses)	3.1	0 %
500 kW$_{th}$ micro-cogeneration (natural gas)	1217	15	36.5	Natural gas (households/businesses)	46 %	41 %
500 kW$_{th}$ micro-cogeneration (biomass)	2160	15	48.4	Biomass (pellets, households/businesses)	65 %	25 %
Grid-bound technologies						
Geothermal	820	30	50.0	Electricity (wholesale)	15	0 %
Centralised solar	785	20	3.9	-	-	0 %
Industrial waste heat 1	250	30	7.5	Waste heat	100 %	0 %
Industrial waste heat 2 (with heat pump)	980	20	29.5	Waste heat, electricity (wholesale)	100 % (heat), 3 (electricity)	0 %
Waste incineration plant	1800	20	27.0	Waste	70 %	12 %
Biomass heating plant	470	20	14.1	Biomass (woodchips, wholesale)	85 %	0 %
Grid-bound cogeneration technologies						
Centralised gas boiler	100	35	3.7	Natural gas (wholesale)	92 %	0 %
Biomass cogeneration	900	20	45.0	Biomass (woodchips, wholesale)	74 %	11 %
Gas and steam power plant	1357	25	52.2	Natural gas (wholesale)	36 %	45 %
Gas turbine power station	585	25	23.4	Natural gas (wholesale)	47 %	33 %

Gas turbine power station with storage	1385	25	52.2	Natural gas (wholesale)	36 %	45 %
Gas turbine power station with storage	613	25	23.4	Natural gas (wholesale)	47 %	33 %

The cogeneration variants 'gas and steam power station with storage' and 'gas turbine power station with storage' refer to the use of day/night storage systems (see Section 6.3.1.3). Seasonal storage systems are not taken into account.

The technologies analysed and their input parameters in industry can be found in Table 6-2. The investment costs per technology are given in accordance with installed capacity.

Table 6-2: Overview of the technologies and parameters analysed in industry (source: see Section 8.1)

Technology	Capacity range in MWth	Investment costs (EUR/kWth)	Service life (a)	Operating/maintenance costs (EUR/kWth*a)	Fuel	Thermal efficiency	Electrical efficiency
Non-cogeneration reference technologies							
Boiler (natural gas)	-	100	35	3.7	Natural gas	92 %	0 %
Fluidised bed boiler	30–200	1100	40	30.0	Waste wood, woodchips	89 %	0 %
Fluidised bed boiler	200–500	975	40	30.0	Waste wood, woodchips	89 %	0 %
Fluidised bed boiler	500–800	800	40	30.0	Waste wood, woodchips	89 %	0 %
Cogeneration technologies							
Gas engine	1–15	868	20	151.4	Natural gas	46 %	37 %
Gas and steam power plant	10–20	2097	25	50.1	Natural gas	36 %	45 %
Gas and steam power plant	20–50	1630	25	50.1	Natural gas	36 %	45 %
Gas and steam power plant	50–100	1324	25	50.1	Natural gas	36 %	45 %
Gas and steam power plant	100–200	1273	25	50.1	Natural gas	36 %	45 %
Gas turbine power station	1–5	1873	25	22.2	Natural gas	47 %	33 %
Gas turbine power station	5–10	1188	25	22.2	Natural gas	47 %	33 %
Gas turbine power station	10–20	1128	25	22.2	Natural gas	47 %	33 %
Gas turbine power station	20–50	867	25	22.2	Natural gas	47 %	33 %
Gas turbine power station	50–100	713	25	22.2	Natural gas	47 %	33 %
Boiler with steam turbine	1–10	69	50	7.2	Natural gas	71 %	9 %
Boiler with steam turbine	10–100	42	50	7.2	Natural gas	71 %	9 %
Boiler with steam turbine	100–200	41	50	7.2	Natural gas	71 %	9 %
Fluidised bed boiler with steam turbine	30–150	1382	40	34.6	Waste wood, woodchips	61 %	28 %
Fluidised bed boiler with steam turbine	150–500	1210	40	34.6	Waste wood, woodchips	61 %	28 %

Fluidised bed boiler with steam turbine	500–800	1037	40	34.6	Waste wood, woodchips	61 %	28 %
Recovery boiler with steam turbine	>1	528	35	30.1	Black liquor, natural gas	39 %	12 %

The other assumptions made are set out below. We have estimated an interest rate of 4 % in line with economic modelling approaches. The cost-benefit analysis is performed on the basis of the technical lifetime of the systems. In order to determine the variable costs of the technologies requiring input of energy in the form of gas, biomass or electricity, required energy quantities per heating (or cooling) unit produced were calculated, taking into account the efficiency rate of the technologies. These energy quantities were then converted into variable costs using price assumptions for 2025 (see Section 6.2.3). In addition, emissions costs were calculated on the basis of emissions factors and a predicted CO_2 price of 25 EUR/tCO_2e. Other environmental costs, e.g. as a result of local emissions of air pollutants, are discussed in Section 7.2.3, but are not included in the quantitative analysis.

A schematic diagram of the method for calculating production costs taking into account all parameters can be found in Figure 6-1.

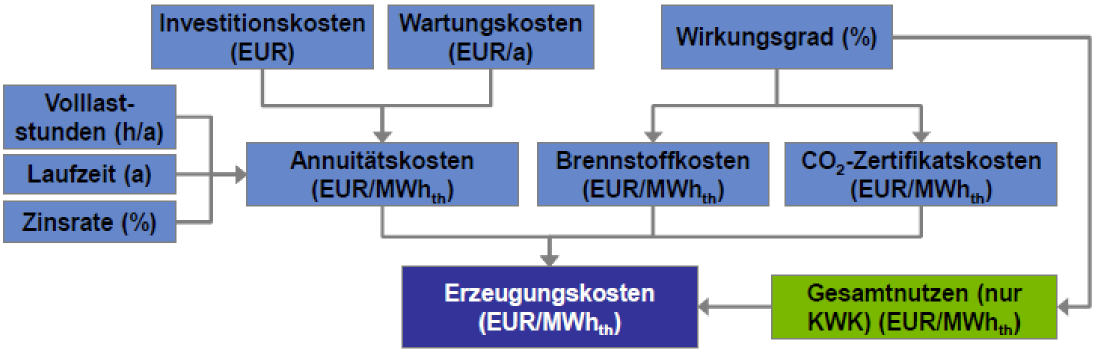


Figure 6-1: Schematic diagram of the method for calculating production costs

Investitionskosten	Investment costs
Wartungskosten	Maintenance costs
Wirkungsgrad	Efficiency
Vollaststunden	Full-load hours
Laufzeit	Lifetime
Zinsrate	Interest rate
Annuitätskosten	Annuity costs
Brennstoffkosten	Fuel costs
CO2-Zertifikatskosten	CO2 certificate costs
Erzeugungskosten	Generation costs
Gesamtnutzen (nur KWK)	Total benefit (cogeneration only)

6.2.2 Network costs

Centralised, grid-bound heat supply sources were determined for household and services consumers (i.e. in the 60–90°C temperature range) depending on the distance between the provider and the consumer and taking into account distribution grid costs. Supply and distribution grid costs were calculated based on a reference grid.

This reference grid has a peak load of 10 MW_{th}, and covers both residential buildings and services companies. An analysis of distribution grid costs depending on heat density and grid capacity (see Figure 6-2) indicated that distribution costs are closely linked to heat density, whilst changes in grid capacity only leads to larger deviations in distribution grid costs in small grids (1 MW_{th}). Cost differentiation was therefore only carried out according to the heat densities in the sub-regions.

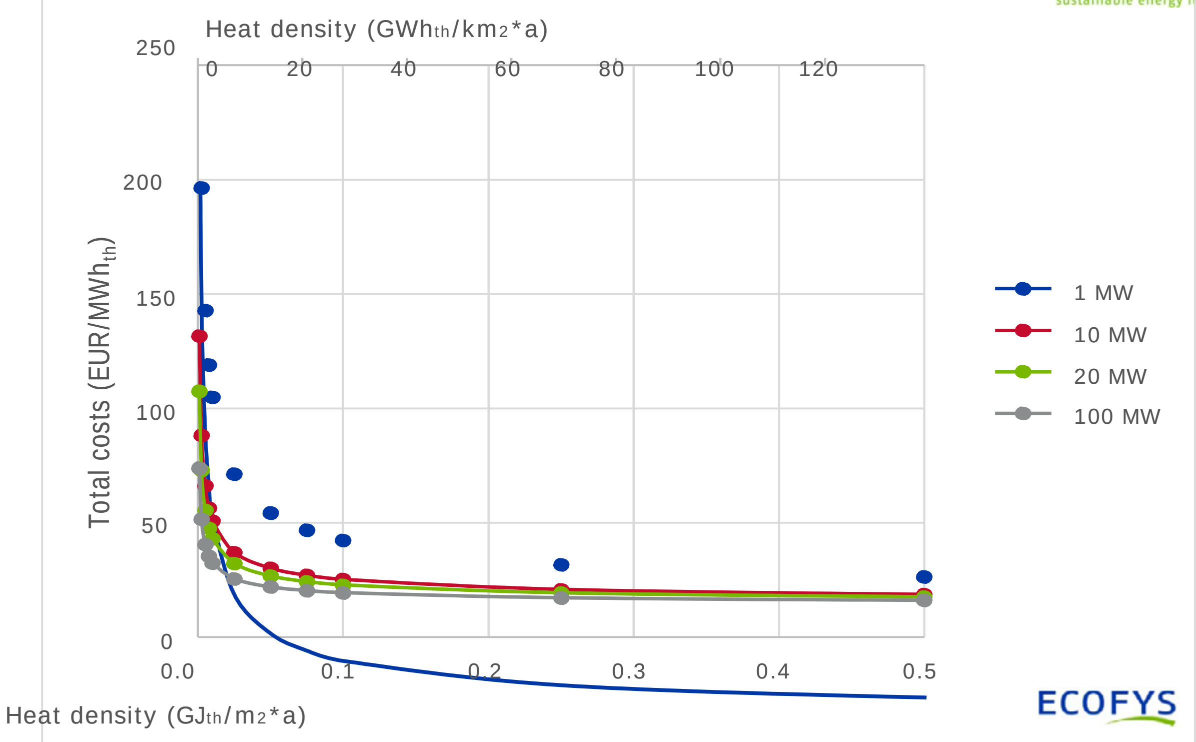
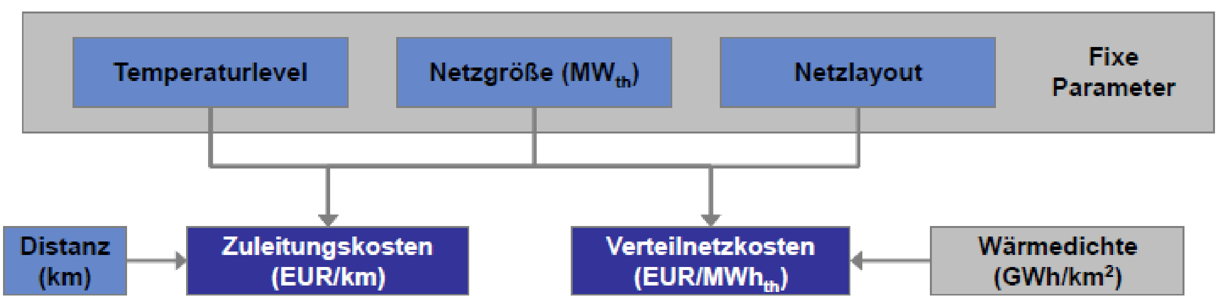


Figure 6-2: Distribution costs according to heat density

The *costs of transmitting* heat from a heat source (e.g. geothermal or industrial waste heat) to the heating grid are calculated on the basis of light soil conditions with existing cables and lines, as the line from the power station to the grid usually runs through sparsely populated areas. The *line costs of the distribution grid* are based on the average costs for various ground types, from light soil to asphalted areas with numerous cables and lines. In this case, distance-dependent transmission costs are given in relation to the whole distance and not per metre of line. This means that the data take account of the structure of the inbound and return lines together.

Figure 6-3 presents the input parameters used to calculate the transmission and distribution costs.



Temperaturlevel	Temperature level
Netzgröße	Grid size
Netzlayout	Grid layout
Fixe Parameter	Fixed parameters
Distanz	Distance
Zuleitungskosten	Transmission costs
Verteilnetzkosten	Distribution grid costs
Wärmedichte	Heat density

Figure 6-3: Input parameters for calculating transmission and distribution costs

6.2.2.1 Transmission costs

The costs of transmitting district heating from the power station to the distribution grid are calculated on the basis of the annualised investment costs for constructing transmission lines and operating and maintenance costs. Pump costs represent less than 1 % of operating costs, and have not been included by way of simplification. On the basis of the model grid, total costs (i.e. annualised investment and operating costs) of 83.5 EUR/m/a are calculated. As regards the supply of heat in industry (100–500°C temperature range), no line costs were calculated under the assumption that in this case, supply and demand normally occur in close proximity to each other in order to avoid substantial transport losses due to the high transmission temperatures.

Transmission costs only account for a significant share of costs in the case of a small number of technologies, as power stations are usually constructed near the distribution grid. Certain heat supply technologies are, however, dependent on the geographical location of the technical potential (geothermal) or individual industries (waste incineration plants and industrial waste heat). In the model, transmission costs are only taken into account for technologies where they represent a relevant share of total costs.

6.2.2.2 Distribution grid costs

Distribution grid costs for district heating were calculated in accordance with specific local demand characteristics. The factors that influence distribution grid costs are:

- availability of an existing district heating grid;
- average heat density;
- the full-load hours of the demand load profile and the connection rate of consumers.

When performing the calculation, it is assumed that the grid has a depreciation period of 30 years, that the interest rate stands at 4 % and that the supply temperature stands at 90°C, with a difference of 25 K between inflow and return flow temperatures.

The distribution grid costs are calculated for five different **heat densities**, covering sparsely populated rural areas up to heavily built-up urban areas. To this end, the heat demand for each region is assigned to one of the five heat density classes below, each of which is subject to an individual economic potential analysis:

- 0–10 GWh/km²
- 10–20 GWh/km²
- 20–35 GWh/km²
- 35–60 GWh/km² and
- >60 GWh/km².

The **full-load hours** of the heating grids in the primary regions examined range from 2350 to 2900 h/a.[13] The costs of the reference grid are estimated on the basis of 2500 full-load hours, which falls slightly below the average for the primary regions. The costs in primary regions with up to 2900 full-load hours deviate by a maximum of 12 % from the distribution grid costs calculated using the reference scenario, depending on their specific heat density. In the secondary regions, heating grids accumulate up to 3140 full-load hours, whereby costs are 17 % higher than those of the reference scenario.

[13] Only one region, Matrei am Brenner, has higher full-load hours.

Due to the generally low output levels there, costs in secondary regions are always slightly underestimated, meaning that higher actual costs are compensated for by the assumption that these regions accumulate fewer full-load hours.

The assumed **connection rate** for sub-regions without heating grids indicates the percentage of heat demand in a region that could potentially be supplied via a heating grid. The connection rate is usually below 100 %, as certain buildings may not be suitable for connection due to technical restrictions or, if no obligation to connect to a grid is imposed, some consumers may refuse to be connected. The connection rate therefore has a direct impact on district heating demand within an area. In the central scenario, a connection rate of 90 % is assumed. Higher rates are rarely achieved in practice, meaning that the economic potential calculated for the central scenario is equivalent to the maximum economic potential. Other studies (see Prognos et al., 2014) have used a similar method for calculating economic potential. Further data and information on the connection rate can be found in Section 4.3.

6.2.3 Fuel prices and CO2 prices

The predicted fuel prices for 2025 can

be found in Table 6-3. The prices indicated are based on historical prices and assumptions with regard to price increases between now and 2025 (see Müller and Kranzl, 2013). When looking at decentralised technologies, a weighted value based on both household and commercial prices is used. Building-related cogeneration (see Section 6.3.1.1) is analysed on the basis of the household or commercial fuel prices for the class of the property in question, meaning that a price range is given here instead. When calculating CO2 costs, the emission factors listed in

Table 6-3 are used, and a CO2 price of EUR 25/tCO2e is assumed.

Table 6-3: Prices for 2025 excluding taxes and duties, adjusted for inflation, and emissions factors for the fuels analysed (source: Agrar Plus 2014, dlv 2015, EEX, Eurostat 2015, IEA 2012, internal Ecofys data, IPCC 2006, Müller and Kranzl 2013)

Fuel	**Market**	**Fuel price (EUR/MWh primary energy)**	**Emissions factor (gCO_2e/MWh primary energy)**
Natural gas	Household	55.5–63.5	0.202
Natural gas	Commercial	47.8–56.6	0.202
Natural gas	Spot price	32.6	0.202
Biomass (pellets)	Household	46.4	0
Biomass (pellets)	Commercial	39.4	0
Biomass (woodchips)	Stock market price	24.8	0
Electricity	Household	135.5	0.416 gCO2e/MWh_{el}
Electricity	Commercial	113.1	0.416 gCO2e/MWh_{el}
Solar		0	0
Waste wood, sawmill by-products	Industry	24.4	0

A more differentiated approach is taken to the analysis of natural gas prices in industry. The natural gas prices listed in Table 6-4 that are used as the basis for calculations are selected depending on total demand at each industrial site.

Table 6-4: Industrial natural gas prices for 2025 excluding taxes and duties, based on historical prices in Austria as at 2012 (source: Eurostat 2015, Müller and Kranzl 2013)

Company consumption in GJ/a (MWh/a)		**Fuel price (EUR/MWh primary energy)**
From...	**To...**	
0	< 1000 (277.8)	56.6
1000 (277.8)	< 10,000 (2777.8)	47.8
10,000 (2777.8)	< 100,000 (27,777.8)	39.6
100,000 (27,777.8)	< 1,000,000 (277,777.8)	34.4
1,000,000 (277,777.8)	< 4,000,000 (1,111,111.1)	35.5

For cogeneration technologies, an hourly electricity price curve is also taken into account in order to illustrate how operating modes vary depending on heat demand and the electricity price. To this end, a pre-modelled electricity price curve for the German-Austrian market for the year 2025 with an average electricity price of 47.2 EUR/MWh and average emissions of 0.416 gCO_2e/MWh_{el} was applied, adjusted on the basis of the fuel prices and CO_2 costs assumed here. The electricity price curve is based on a detailed operational electricity market model, which determines the most cost-effective operating mode for power stations for a given power plant fleet and a given share of renewables in the entire area covered by the electricity market.

The electricity market model depicts power plant usage and operating mode at individual plant level. In the model, the spot markets and intra-day markets are presented separately, allowing errors in short-term wind power forecasts to be taken into account and resulting in more realistic modelling. The electricity market model was calibrated on the basis of past developments.

6.3 Methodology

The most cost-effective technology mix in the two demand scenarios is determined separately for heat and cooling demand.

Generation costs are first calculated per technology combination (e.g. district heating cogeneration with peak load boiler). These costs depend on full-load hours, inter alia, and therefore vary according to the demand load profile and the region. It is also assumed that the technology combinations generate the same amounts of energy and do not just cover individual load areas, i.e. that all technology combinations have the same full-load hours in principle. For technologies connected to heating grids, combined generation with a peak load boiler is also assumed. The operating mode of cogeneration plants is assumed to be electricity-controlled (see Section 6.3.1.3). Building-related cogeneration is analysed on the basis of the load profiles of various sites.

As regards industrial heat demand, it is assumed that this is covered exclusively using decentralised technologies. Process-dependent steam demand in industry exceeds the temperature level required for heating purposes, meaning that industry cannot usually be supplied via the same district heating grids as those used to supply households and businesses. As such, potential for industry is calculated separately.

A more thorough examination of cooling demand in industry has not been carried out. As demonstrated in Section 2.1.2, industry only accounts for a very small share of cooling demand.

6.3.1 Heat supply for households and businesses

The diagram in Figure 6-4 depicts the process of modelling heat supply and the relevant parameters for households and businesses in one region. The detailed methodology for determining the economic potential for district heating and cogeneration is explained below.

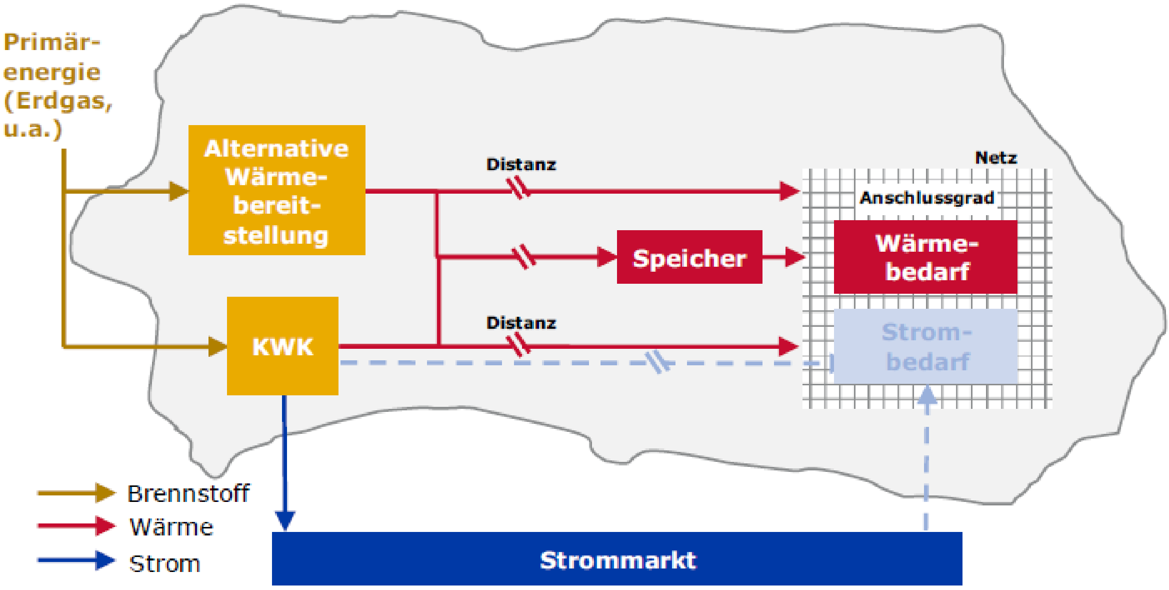


Figure 6-4: Diagram illustrating the modelling process for the supply of heat to households and businesses

Primärenergie (Erdgas, u.a.)	Primary energy (e.g. natural gas)
Alternative Wärmebereitstellung	Alternative heat supply
KWK	Cogeneration
Brennstoff	Fuel
Wärme	Heat
Strom	Electricity
Distanz	Distance
Speicher	Storage
Netz	Grid
Anschlussgrad	Connection rate
Wärmebedarf	Heat demand
Strombedarf	Electricity demand
Strommarkt	Electricity market

The most cost-effective technology mix in the area of households and businesses is determined for each of the 38 primary regions and 30 secondary region types. For each region, areas already connected to district heating grids and those without grids are examined separately. Furthermore, the heat demand of each of these two groups of areas is sub-divided into five heat density classes. This results in 10 sub-regions per region.

The following steps are taken for each region:

1. For each region, the heat demand in the 10 sub-regions is calculated. Each of the sub-regions is examined in sequence, starting with the sub-regions which already have a grid and working downwards from the highest heat density class.
2. The remaining installed grid-bound heat capacity for 2025 is calculated on the basis of the technical lifetime of the power plants. Generation from existing capacity is calculated using the load curves for each region, and then subtracted from the heat demand in regions already connected to district heating grids. In doing so, generation from existing capacity is limited to total grid-bound generation capacity in 2012, with priority accorded to must-run technologies such as waste incineration plants and industrial waste heat.

a. If existing capacity is not sufficient to cover heat demand in the grid-connected regions, the most cost-effective technology mix for covering the remaining demand is determined. This is done taking into account all technologies, meaning that decentralised technologies may also represent the most cost-effective solution, which may in turn mean dismantling/ceasing use of the existing grid. For grid-bound technologies, however, no investment costs are taken into account for the distribution grid, as this is already in place.

b. If generation through existing capacity exceeds grid-bound demand (e.g. due to a fall in heat demand), the available capacity is used to cover demand in sub-regions without district heating, starting with the sub-region with the highest heat density.

3. The technical potential of the technologies examined is determined per region depending on distance from demand (see Section 4).

4. Subsequently, heat demand not covered by existing capacity is covered for each sub-region using the most cost-effective technology mix. The procedure is as follows:

a. On the basis of the merit order of the technologies, which takes account of both technology costs and transmission and distribution grid costs (see Section 6.3.1.2), the most cost-effective technology is selected. Considerations of grid-bound technologies include coverage of peak demand by peak load boilers. This is done in such a way that the top 10 % of heat demand is assumed to be covered by the peak load boilers. In the case of cogeneration, generation from peak load boilers may be higher depending on whether the plants are electricity-controlled or not.

b. In addition, heat demand must exceed a specified minimum power plant size. This takes into account the fact that large electricity plants would be excessively big for supplying smaller grids, for example.

c. Once the potential of a technology is exhausted, the next most cost-effective technology is selected. If potential is exhausted in one sub-region, that technology has no further potential available for other sub-regions.

d. These steps are repeated until the demand in the sub-region has been covered.

The most cost-effective technology mix for supplying heat is determined for each sub-region using this approach. On the basis of this, the most cost-effective share of district heating and cogeneration technologies as well as average technology costs (including network costs) can be calculated. For existing grids, only maintenance and operating costs are taken into account.

The potential for each secondary region as a whole is calculated by analysing the 30 representative model regions determined. The potential calculated for each secondary region is scaled according to the number of regions falling under the relevant type.

6.3.1.1 Decentralised heat supply from CHP plants

After the analysis of the potential of district heating, an analysis of the potential of decentralised cogeneration is conducted. In doing so, the proportion of heat demand per region not already covered by district heating and where there is no potential for such coverage is examined separately. The analysis of the potential of building-related cogeneration is performed on the basis of an analysis of individual sites demonstrating sufficient demand levels to enable cost-effective operation of a CHP system (see Section 2.3.2).

The cogeneration technologies examined are assumed to be heat-controlled. In addition, it is assumed that the top 10 % of heat demand is covered by a decentralised gas boiler that acts as a peak load boiler, which can be used as a back-up in the event of maintenance or malfunctioning of the CHP plant. Revenue from electricity for the CHP plants is calculated on the basis of the average electricity price, assuming a fixed rate applies. The most cost-effective decentralised supply option is determined for each building category on the basis of the merit order of the decentralised technologies. Already existing capacity is not taken into account. This is because the most cost-effective time to install a CHP plant is usually before the end of the technical lifetime of the previously used technology (usually oil or gas boilers), which are then used as back-up boilers.

6.3.1.2 Determining the merit order

A merit order of all heat supply technologies examined is drawn up for each sub-region. This is based on the specific costs per unit of heat supplied to the consumer for each technology, which encompass the following factors:

- Generation costs for the technology:
  - investment costs, taking into account lifetime and full-load hours
  - operating and maintenance costs, taking into account full-load hours
  - fuel and CO_2 costs
  - electricity credits for cogeneration technologies.
- Transmission costs (for grid-bound technologies whose geographical location is dependent on technical potential or particular industrial sites):
  - investment costs (not for existing capacity)
  - operating and maintenance costs.
- Distribution grid costs (for grid-bound technologies):
  - investment costs (not in the case of existing grids)
  - operating and maintenance costs
  - pump costs.

Taking into account generation and network costs, decentralised and grid-bound technologies are directly compared in terms of the costs of supplying heat.

The generation costs for grid-bound technologies per unit of heat supplied to the consumer include network losses in the distribution grid. Furthermore, it is assumed that grid-bound technologies are run in conjunction with a peak load boiler designed in such a way that it covers peaks in the heat load curve, thereby accounting for the top 10 % of heat demand per year. Depending on the demand load curve for the region in question, this means that the peak load boiler accounts for around 60 % of the total capacity and the technology being examined accounts for around 40 %. A weighting is therefore applied to generation costs for grid-bound technologies, whereby 90 % of heat demand is covered by the technology being examined and 10 % by a peak load boiler. Gas and steam power stations as well as gas turbine power stations are assumed to be electricity-controlled, meaning that the generation spread may deviate slightly for these technologies (see Section 6.3.1.3).

The generation costs for decentralised technologies are determined based on a load profile for an old, detached house. The full-load hours for this load profile stand at 1900 h/a, which is lower than for total heat demand in the regions. This is done in order to take account of the fact that simultaneously supplying many consumers leads to a reduction in load peaks due to the simultaneity factor.

The technologies are assumed to be designed to cope with only a small number of extremely cold winter days (as low as around -20°C). In order to guarantee coverage of heat demand on these days, installed capacity is estimated at 20 % higher than the peak load for an average year. In the case of grid-bound technologies, this over-estimation is applied on the basis of a total load curve for the region, and in the case of decentralised technologies on the basis of the typical household load curve. The 60:40 ratio between peak load and the technology examined, as referred to above, includes this over-estimation of the capacity of the peak load boiler.

A breakdown of heat supply costs for a sample biomass heating plant, divided into the various cost components of generation and distribution grid costs, is given in Annex 11.1.

6.3.1.3 Determining the operating mode and electricity revenue of cogeneration technologies

Revenue on the electricity market, which has a substantial impact on the competitiveness of cogeneration technologies, is calculated using a future hourly spot price curve (see Section 6.2.3), under the assumption that the technologies are electricity-controlled.

Waste incineration plants and **biomass heating plants** are not usually operated in an electricity-controlled mode. Waste incineration plants mostly run permanently, whilst biomass heating plants are usually operated in a heat-controlled mode due to the high heat to electricity ratio.[14] For biomass heating plants, an average electricity price depending on heat demand is calculated on the basis of a heat-controlled operating mode; for waste incineration plants, an average annual electricity price is calculated.

Gas and steam power stations and gas turbine power stations are assumed to be electricity-controlled due to their high degree of electrical efficiency. In **gas and steam power stations**, the thermal to electrical output ratio can vary. At 100 % thermal output, the power station is run at around 45 % electrical and 36 % thermal efficiency. If the thermal output is completely reduced (0 % efficiency), electrical efficiency rises to around 52 %. **Gas turbine power stations** have a fixed thermal to electrical output ratio. It is assumed that output cannot be varied, and that residual heat therefore goes unused in the event of low heat demand. Gas power stations are run in conjunction with a peak load boiler. This is used on the one hand to cover peak loads, and on the other as a back-up technology in the event of low electricity prices. The capacity of the peak load boiler is determined in the same way as for all grid-bound technologies, namely on the basis of coverage of the top 10 % of demand, and stands at approximately 60 % of total installed capacity.

Whether the grid-bound gas cogeneration plant examined is heat-controlled or electricity-controlled depends on heat demand in the region and electricity prices. For gas power stations and for peak load boilers, the marginal costs per hour are calculated on the basis of fuel costs, CO_2 costs and, in the case of cogeneration, electricity revenue. If the costs of a gas power station exceed the costs of the peak load boiler, the cogeneration facility is not run. One exception to this is cases where the peak load boiler cannot sufficiently cover heat demand due to its limited capacity. During such times, the cogeneration facility must also be run, despite high costs.

In addition, gas power stations are examined taking into account the existence of a **day/night storage system**. To this end, it is assumed that heat demand for one day can be covered irrespective of the time at which demand arises. This makes it possible to generate power at the point in the day when electricity prices are the highest. The resulting surplus revenue compensates for higher investment, operating and maintenance costs for the construction and running of the storage system.

[14] It should be noted here that no feed-in tariffs for biomass cogeneration plants were taken into account due to the economic approach taken.

6.3.2 Cooling supply for households and businesses

Cooling can be supplied in three ways: in a decentralised manner using compression chillers (air conditioning systems), in a decentralised manner using absorption chillers and centrally generated district heating, or in a centralised manner via district cooling plants in conjunction with a separate district cooling grid. The latter option depends heavily on local conditions, and as such is not suitable for an analysis of generally applicable approaches (see Section 6.6.3). For all regions in which potential for district heating was identified, a comparison of the costs of compression and absorption chillers is made, taking account of technical potential.

Cooling demand is determined for the sub-regions defined during analysis of heat supply, broken down by heat density classes. It is assumed that during the cooling period (May to September), 90 % of installed grid-bound heat capacity can be used for cooling purposes. The installable capacity for each sub-region is calculated on the basis of the efficiency of absorption chillers.

The comparison of the costs of compression and absorption chillers is performed using a typical cooling load profile for office buildings with full-load hours of 450 h/a. For **absorption chillers**, it is assumed that peak load is covered by compression chillers. To this end, a basic load to peak load ratio of 40:60 is assumed. This corresponds to peak load coverage amounting to 10 % of cooling demand and full-load hours to cover the basic load of approximately 1000 h/a.

The fuel costs for absorption chillers comprise both the cost of the electricity used and the cost of the district heating used. The latter cost depends on the technology mix used for grid-bound heat supply. In the case of must-run heat supply technologies like waste incineration plants and industrial waste heat, the heat generated cannot be used in summer. Absorption chillers therefore represent a way of making use of unused heat in the summer; as such, if must-run technologies are available, it may be assumed that district heating costs are equivalent to zero. For other district heating technologies, an average district heating price is calculated.

The fuel costs for compression chillers are purely based on the electricity used to generate cooling. Absorption chillers consume less electricity than compression chillers, but are associated with higher investment costs.

6.3.3 Heat supply in industry

On the whole, district heating is used very rarely or not at all in industry due to the high temperatures required. As such, only the economic potential for cogeneration is calculated for industry.

Unlike in the case of households and businesses, when determining the most cost-effective technology mix for industry there is no need to calculate demand on a regionally disaggregated basis, as industrial cogeneration is independent from district heating cogeneration.

The economic potential of cogeneration in industry is determined individually for different sectors of industry (see Section 4.4.4). For each sector, various typical sites that vary in terms of the level and structure of heat demand are examined. Smaller sites are examined in clusters. For each site/cluster in the various sectors, a cost-effectiveness analysis for the use of cogeneration is carried out.

This analysis is based on the predicted heat demand at individual industrial sites for 2025. It only takes account of the proportion of demand whereby steam at temperatures of up to 500°C is required. At higher temperatures, there is no suitable scope for application of cogeneration. Consumption trends up to 2025 are calculated per sector (see Section 2.1.2).

It is assumed that already existing cogeneration plants will still be in operation in 2025, or will have been replaced where necessary. The demand currently covered by way of other technologies is examined for additional cogeneration potential taking into account changes in consumption. This potential is either calculated by comparing different cogeneration technologies to the most-used non-cogeneration technology in each sector, or, in those sectors in which almost 100 % of their heat is supplied via cogeneration, by comparing different cogeneration technologies to gas boilers.

Table 6-2 provides a list of the cogeneration technologies examined and their properties. Account is taken of the fact that certain technologies can only be included in the analysis if sufficient waste material is produced in industry (recovery boilers with steam turbines) or if there is adequate demand for additional capacity (in particular gas and steam). During the analysis, the plant size and therefore costs are selected on the basis of the demand to be covered.

In the case of waste material usage in the wood industry (waste wood, sawmill by-products), a reference price is used, as there is also potential for use of this waste material in other markets (pellets, material use). If the waste material would not be sufficient to run a fluidised bed boiler, it is assumed that woodchips would be purchased. Black liquor produced in the pulp industry must be incinerated on-site as a result of the processes used, meaning that a price of zero is assumed in this case. Gas is used as a supplementary fuel in the case of recovery boilers with steam turbines. The costs of fuel and of CO_2 certificates are determined using a weighting depending on the proportion of the fuels used.

Revenue from electricity production is calculated according to the modelled hourly electricity price. To this end, the industrial sites are divided into four different consumption groups, with an average electricity price calculated for each group. For the sake of simplification, an average electricity price during operating hours is calculated, as heat demand normally depends heavily on operating hours. As such, partial-load operation is not taken into account when it comes to operation of the heat supply technologies either.

The individual companies are then allocated to the different consumption groups on the basis of their heat demand full-load hours. These groups can be found in Table 6–5.

Table 6-5: Allocation of the industrial companies to consumption groups

Sector	Continuous load profile	No weekend operation, continuous during the week	No night-time operation (operating hours between 6 a.m. and 6 p.m.)	No night-time or weekend operation
Pulp and paper		X		
Wood industry		X		X
Chemicals industry	X		X	
Food materials industry				X
Manufacture of machinery and equipment n.e.c.			X	
Vehicle construction			X	

6.3.4 Efficiency analysis of the economic potential for district heating and cooling

The economic potential for district heating and cooling is then analysed in terms of efficiency. No overall analysis of the entire district heating grid, including existing capacity, is carried out. This makes it possible to perform a separate analysis of the efficiency of the calculated economic potential. In the case of an inefficient district heating grid being expanded via an efficient technology mix, this prevents this expansion being regarded as inefficient if the entire district heating grid still does not meet the threshold value for classification as efficient. This approach also prevents inefficient additional potential for expansion of an efficient district heating grid from being regarded as efficient.

The analysis and illustration of efficiency is done on the basis of the aggregated additional potential calculated for each region.

In accordance with Article 2(41) of Directive 2012/27/EU, the efficiency of district heating and district cooling systems depends on the shares of the technologies used. If at least 50 % renewable energy, 50% waste heat, 75 % cogenerated heat or 50 % of a combination of such energy and heat is used, the system may be regarded as efficient (see Section 4).

Whether the economic potential for cogeneration may be regarded as 'high-efficiency' is determined per region and per cogeneration technology. According to the Annex II Interpretative Notes (Guidance Note on Directive 2012/27/EU, 2013), cogeneration systems may be regarded as high-efficiency systems when savings in primary energy of at least 10 % can be made through combined generation compared to the separate production of heat and electricity.

Primary energy savings (PES) are calculated using Equation 6-1 in accordance with the Annex II Interpretative Notes (Guidance Note on Directive 2012/27/EU, 2013) on the basis of the heat efficiency η_W and the electrical efficiency η_E of the cogeneration production as well as the harmonised efficiency reference values for separate heat production (η_{refW}) and separate electricity production (η_{refE}). The cogeneration efficiency rate is determined on the basis of the ratio of usable heat or electricity generated to primary energy consumption.

$$PES = \left(1 - \frac{1}{\frac{\eta_W}{\eta_{refW}} + \frac{\eta_E}{\eta_{refE}}} \right) 100$$

Equation 6-2

The efficiency reference values listed in Table 6-6 were calculated for each fuel in line with Commission Implementing Decision 2011/877/EU,[15] and were adjusted according to the difference in average temperature for Austria compared to the ISO standard conditions of 15°C, namely by 0.1%/°C. In doing so, an average temperature of 9°C was postulated for Austria based on normal values in non-Alpine regions between 1981 and 2010 according to ZAMG (2015).

Table 6-6: Temperature-adjusted efficiency reference values for the separate generation of heat and electricity in line with Implementing Decision 2011/877/EU

Fuel	Efficiency reference value Heat η_{refW}	Efficiency reference value Electricity η_{refE}
Natural gas	90.6 %	53.1 %

[15] Commission Implementing Decision 2011/877/EU establishing harmonised efficiency reference values for separate production of electricity and heat in application of Directive 2004/8/EC of the European Parliament and of the Council and repealing Commission Decision 2007/74/EC.

Biomass	86.6 %	33.6 %
Waste	80.6 %	25.6 %

In industry, if the cogeneration unit is operated with more than one fuel the harmonised efficiency reference values for separate production shall be applied proportionally to the weighted mean of the energy input of the various fuels.

6.4 Economic potential for efficient district heating

The results of the analysis give rise to a total potential for efficient district heating throughout Austria and per region, which is discussed in more detail in the section below.

By way of example, Figure 6-5 depicts the specific heat supply costs calculated under Section 6.3.1.2 for a sample region in the area of households and businesses under the central scenario. Waste heat 1 refers to the waste heat potential over 100°C determined under Section 4.5, and Waste heat 2 the waste heat potential below 100°C. The costs are given for each individual technology, broken down into generation costs, transmission costs and distribution grid costs depending on heat density. Distribution grid costs rise as the heat density falls. The costs of grid-bound technologies vary from region to region, but the costs of building-related technologies do not. However, the costs given are representative of all regions.

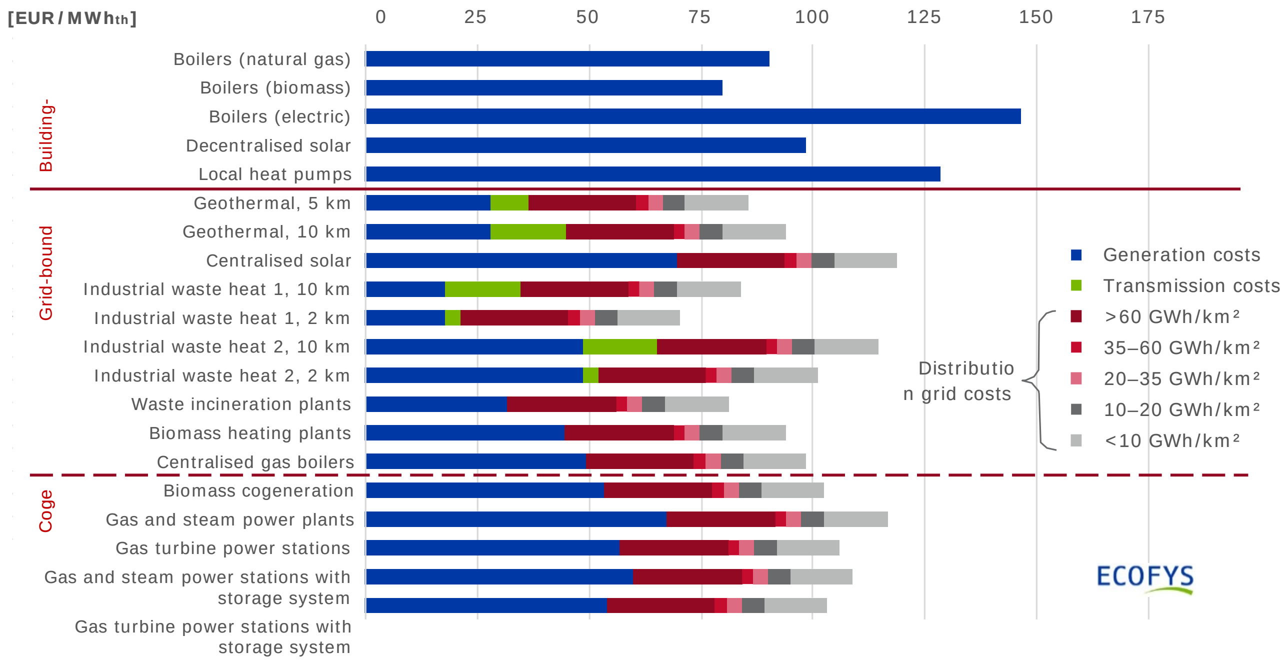


Figure 6-5: Merit order of technologies for a selected region

As can be derived from the figure, biomass and natural gas boilers are the most cost-effective building-related technologies. It is important to note here that the potential of biomass is limited, meaning that once the technical potential within a region has been exhausted, the next most cost-effective technology is resorted to. The most cost-effective centralised technologies, namely geothermal, industrial heat 1 and waste incineration plants, solely generate higher costs than building-related technologies at heat densities below 10 GWh/km². However, areas with a heat density of below 10 GWh/km² only demonstrate a relevant share of heat demand in a small number of secondary regions, meaning that geothermal, industrial waste heat 1 and waste incineration plants represent the most cost-effective form of heat supply wherever there is technical potential available. Furthermore, in areas with a high heat density, which account for a large proportion of total heat demand in the primary regions in particular, the costs of biomass heating plants fall below the costs of building-related heat supply.

The costs indicated for centralised solar thermal energy indicate negligible economic potential in two regions. It should be noted though that these are subject to a high degree of uncertainty due to the major dependency of such costs on location and changes in technology costs. The most cost-effective grid-bound technology without a limited technical potential (with the exception of certain secondary regions) is centralised gas boilers. In the region given by way of example, the specific costs at a heat density of 20 to 35 GWh/km² are equal to the costs of building-related biomass boilers, the most cost-effective building-related technology. It can therefore be deduced that in areas with a higher heat density, there is economic potential to be found in supplying heat by way of district heating. At the same time, Figure 6-5 also suggests that the decision as to whether there is economic potential for district heating in a region or not is based on very minimal differences in cost. As such, minor changes in the input parameters affecting specific costs may impact the economic potential of individual regions.

Figure 6-5 also demonstrates that all cogeneration technologies incur higher specific costs than biomass heating plants and centralised gas boilers, meaning that district heating not using cogeneration is more cost-effective from an economic perspective. Furthermore, it is only in the case of biomass cogeneration and gas and steam power stations with storage systems that the costs in the highest heat density areas are lower than those for the most cost-effective building-related heat supply technology.

The percentages accounted for by investment costs and operating expenses (operating and maintenance costs, fuel costs, CO_2 costs) vary between the different technologies. Local boilers are characterised by high operating costs of around 70 % in the case of biomass boilers, around 90 % for gas boilers and almost 100 % for electric boilers. In the case of local heat pumps, on the other hand, almost 50 % is accounted for by investment costs. In the case of grid-bound technologies, the percentage accounted for by investment costs is higher than in the case of building-related technologies due to the lower specific operating costs resulting from the size of the systems. Investment costs account for around 25 % of generation costs in the case of biomass cogeneration and gas and steam power stations. As for gas turbine power stations, investment costs are lower, standing at 14 %. In the case of geothermal, industrial waste heat and centralised solar thermal power, the share of investment costs stands at between 35 % and 80 %. Due to low investment costs, 95 % of the costs of centralised gas boilers are accounted for operating costs. The production costs determined for building-related heating systems were calculated for medium-sized reference buildings, and may in some cases vary depending on the size of the building and the heat load.

Figure 6-6 shows the results of the calculation of the economic potential of district heating under the central scenario for the seven largest primary regions and aggregated for the remaining primary regions and the secondary regions. A detailed overview of the results for the secondary regions can be found in Figure 11-1 in annex. In this figure, total heat demand per region in 2025 is represented by a bar, sub-divided according to the results of the analysis of the most cost-effective heat supply technology. The figure also portrays the supply of heat from existing district heating capacity, efficient[16] and non-efficient economic potential for district heating, and demand covered by decentralised supply. For the secondary regions, no existing capacity is taken into account. The economic potential is also compared to the supply of heat via district heating in 2012.

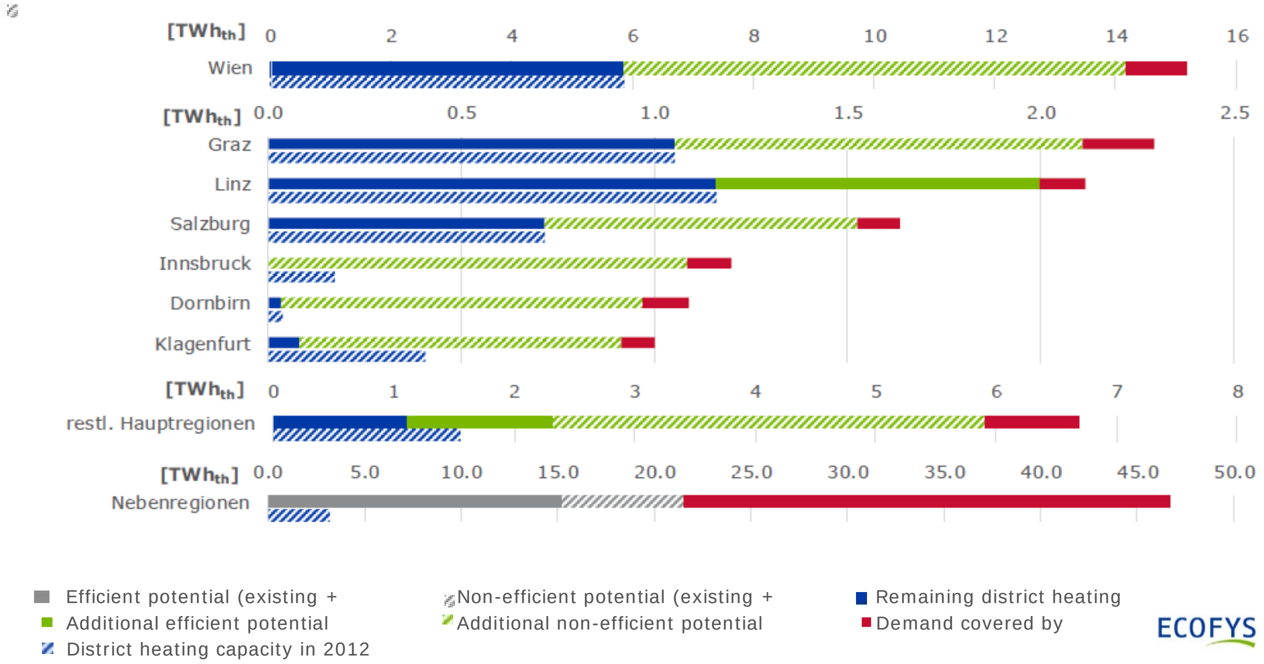


Figure 6-6: Heat supplied via district heating in 2012, heat supplied by existing district heating in the 2025 scenario and (efficient) economic potential for district heating in 2025 for the central scenario17

Wien	Vienna
Restl. Hauptregionen	Remaining primary regions
Nebenregionen	Secondary regions

In most regions, the 2012 district heating supply capacity will still be available to cover heat supply in 2025. Moreover, there is substantial economic potential for district heating, amounting to a total of 40.3 TWh_{th} per year. It is only in the secondary regions, which are characterised by lower heat densities, that it is more cost-effective to cover the majority of demand via decentralised technologies. In spite of this, there is still economic potential in the secondary regions of 21.6 TWh_{th} per year, which is equivalent to over 50 % of the total potential.

Efficiency is determined on the basis of the technology mix for the calculated economic potential (see Section 6.3.4). As such, no statements are made regarding the efficiency of the entire district heating grid including existing capacity. Furthermore, the efficiency values given are based on the operating mode determined for the power stations. A change in actual operation (e.g. in favour of increased use of cogeneration) may have a positive effect on efficiency. For example, the designation of the additional economic potential in Vienna as 'non-efficient' should be taken to mean that the most cost-effective solution in the central scenario, according to the model, would be to expand the use of gas boilers due to relatively low electricity revenues. It should be noted, though, that if existing cogeneration plants

[16] For a definition of 'efficient district heating', please refer to Section 6.3.4.

[17] Efficiency is only shown for new facilities that would need to be built in order to exploit the additional economic potential, under the assumption that the most cost-effective technology (primarily gas boilers) would be used. As such, no statements are made regarding the efficiency of the entire expanded district heating grid including existing capacity.

were exploited more extensively, this would indeed result in additional efficient district heating potential. The sensitivity analyses indicate that under different conditions, a much larger proportion of the economic potential would be regarded as efficient within the meaning of the Directive.

The efficiency analysis of the potential shows that 43 % of economic potential in all regions can be designated as efficient. The picture does, however, vary between secondary and primary regions. Whilst much of the economic potential in the primary regions is non-efficient, 71 % of potential in the secondary regions is efficient. This is because in the secondary regions, the technical potential for biomass in relation to heat demand is higher than in the primary regions, meaning that a larger share of demand can be covered by biomass. In addition, certain secondary regions are not connected to the gas grid, meaning that supply via natural-gas-fired technologies is not taken into consideration in these regions, resulting in increased use of biomass. In some of the primary regions, however, the additional economic potential for district heating can be regarded as efficient thanks to the use of industrial waste heat in combination with biomass. The economic potential calculated may vary subject to fluctuations in the input parameters. In Section 6.8, the results are analysed for their sensitivity to changes in some of these parameters.

6.5 Economic potential for high-efficiency cogeneration

6.5.1 Economic potential in the area of households and businesses

The analysis provides an estimate of the total potential for cogeneration for the whole of Austria and for each individual region, as well as the additional economic potential for the supply of heat from new plants and the percentage of total heat supply accounted for by cogeneration. This is illustrated below.

The diagram in Figure 6-7 shows the results of the calculation of the economic potential of grid-bound and building-related cogeneration for the seven largest primary regions and aggregated for the remaining primary regions and the secondary regions. Here, the economic potential is measured against heat supply from the grid-bound cogeneration capacity that will still be in operation in 2025.

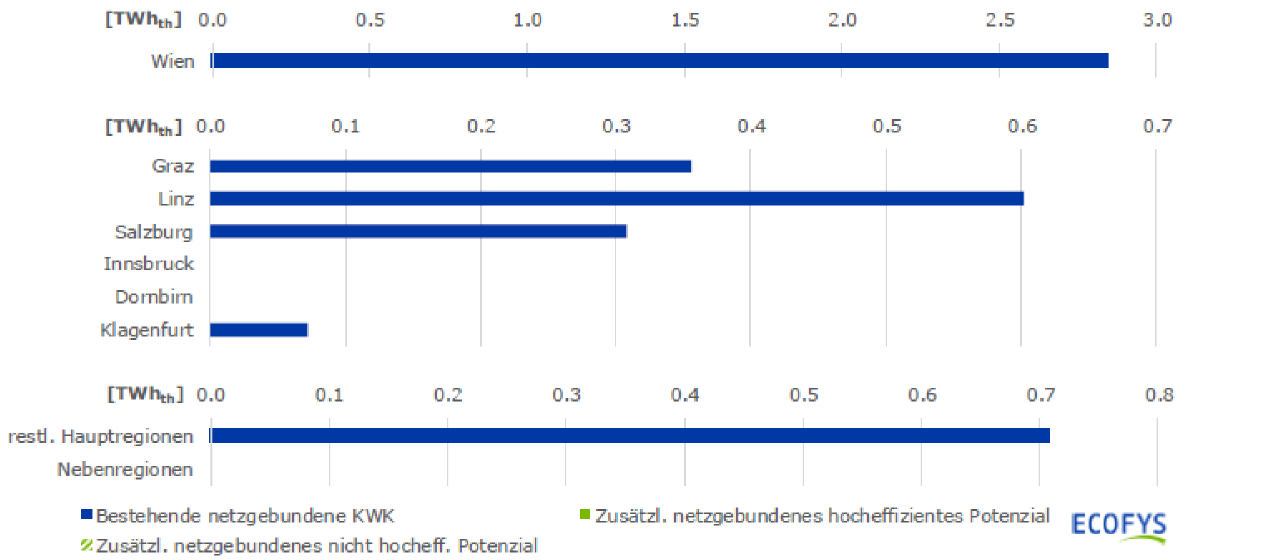


Figure 6-7: Existing heat supply capacity in 2025 and economic potential for cogeneration in the central scenario

Wien	Vienna
Restl. Hauptregionen	Remaining primary regions
Nebenregionen	Secondary regions
Bestehende netzgebundene KWK	Existing grid-bound cogeneration
Zusätzl. Netzgebundenes nicht hocheff. Potenzial	Additional grid-bound non-high-efficiency potential
Zusätzl. Netzgebundenes hocheffizientes Potenzial	Additional grid-bound high-efficiency potential

As can be seen in the figure, there is no additional economic potential for cogeneration in 2025 under the predicted conditions.

The technical advantage of cogeneration is that heat and electricity can be produced simultaneously, resulting in greater overall efficiency than in the case of separate production. However, it does entail higher investment costs compared to heat-only technologies using the same fuel, and the cost-benefit analysis shows that the additional revenue from electricity sales is not sufficient to offset these higher investment costs. Generating heat using a centralised gas boiler or a biomass heating plant is more cost-effective than using centralised biomass or gas cogeneration plants.

For grid-bound gas cogeneration plants, an optimised operating mode is determined on the basis of hourly potential electricity yields and heat demand. Such power stations are only profitable if demand for heat and the spot price for electricity are sufficiently high. However, on the basis of the assumed electricity price of 47.2 EUR/MWh$_{el}$ on average, such cogeneration plants would not accumulate enough operating hours.

Small cogeneration systems used to supply households and business are assumed to be heat-controlled, receiving remuneration at the average spot electricity price. For certain building categories, depending on their heat load profile, the systems accumulate a large number of full-load hours, meaning that investment costs per unit of heat produced have only a minor influence on overall costs. However, in this case too, the specific heat generation costs for the separate production of heat are lower than the production costs for cogeneration, which means that there is no economic potential for cogeneration. Across the various building categories, the costs of the cogeneration technologies are between 30 % and 36 % higher than the costs of the most cost-effective building-related technology. Only electric boilers incur higher costs than cogeneration plants. The most cost-effective building-related technology in all cases is decentralised biomass boilers. In the case of the cogeneration technologies, the specific heat costs of biomass-fired cogeneration plants are lower than those of gas-fired cogeneration plants.

6.5.2 Economic potential in industry

The calculated economic potential for cogeneration in industry can be found in Figure 6-8. The figure depicts total demand per sector analysed, broken down into existing cogeneration supply capacity, additional cogeneration potential and demand without further cogeneration potential. In this case, economic potential for cogeneration is divided into high-efficiency and non-high-efficiency potential.[18]

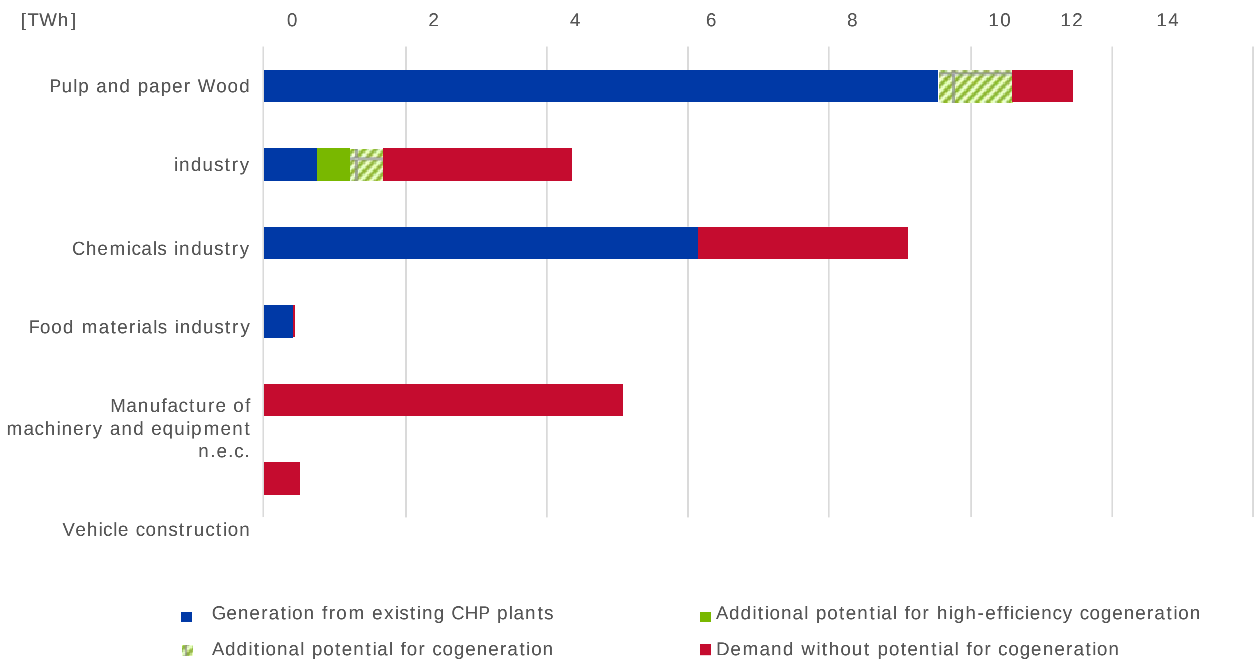


Figure 6-8: Heat supply from existing cogeneration plants and (high-efficiency) economic potential for cogeneration in industry in 2025 for the central scenario

The results indicate that in the paper and pulp sector as well as in the wood industry, there is further economic potential for cogeneration. In the chemicals industry and the food industry, whose heat demand is already covered to a substantial degree by cogeneration, there is no additional potential.

50% of the additional economic potential in the wood industry can be classed as high-efficiency, this being a result of the economic potential for fluidised bed boilers with steam turbines in larger panel production companies. This technology has a high overall efficiency rate, and therefore generates significant primary energy savings compared to separate production of heat and electricity. The economic potential in the paper and pulp industry, on the other hand, is not classed as high-efficiency in line with the definition in Section 6.3.4. Here, it is mostly recovery boilers with steam turbines that are used, which have a low total efficiency rate of around 51 %. The analysis of the efficiency of recovery boilers with steam turbines should, however, be scrutinised further, as the black liquor is a by-product of certain processes and is reused on-site. In this case, the generation of heat and electricity is not the main priority.

[18] For a definition of 'efficient district heating', please refer to Section 6.3.4.

6.6 Economic potential for grid-bound cooling

6.6.1 Economic potential for district-heating-based cooling

A comparison of the costs of providing cooling via air conditioning systems (decentralised compression chillers) and via absorption chillers whereby heat is supplied through the district heating grid and through air conditioning systems at peak times shows that even if district heating was supplied for absorption chillers free of charge, air conditioning systems are still the most cost-effective option. The costs of air conditioning systems per unit of cooling fall more than 15 % below the costs of district-heating-based cooling. This means that even in the case of district heating grids with unused waste heat in summer, for example from waste incineration plants or industrial processes, it is still more cost-effective under the assumptions made here to provide cooling by way of decentralised air conditioning systems.

An analysis of the costs shows that the additional costs linked to absorption chillers can be attributed to investment costs. For absorption chillers, the investment costs per unit of installed capacity are almost three times as high as for air conditioning systems (see Table 6-1). For this reason, peak load cooling demand is covered by an air conditioning system where absorption chillers are used, as a large capacity that is only used for short periods of time is required.

As regards variable costs, absorption chillers are at an advantage, as their fuel and CO_2 costs are lower due to their low electricity consumption (in cases where heat is supplied free of charge). Due to the low number of cooling demand full-load hours, however, the investment costs have a major impact on the specific costs per unit of cooling generated, meaning that the cost advantage of absorption chillers in terms of variable costs has a limited effect on total costs. This also means that supplying cooling via absorption chillers may present an interesting alternative in the case of applications with a relatively large number of full-load hours, such as hospitals.

6.6.2 Cost-effectiveness of district heating in the case of district-heating-based cooling

Cooling via absorption chillers using district heating has an effect on the heat load profile of the region. Due to the low demand for heat in the summer, most of which is accounted for by warm water, using district heating in summer for purposes other than heating can significantly increase the heat load. As peak load times for heat demand on cold winter days are often accompanied by little or no cooling demand, these times and the heat capacity required remain unchanged, resulting in an increase in the full-load hours for heat demand.

Must-run technologies such as waste incineration plants and industrial processes with usable waste heat may also generate heat in summer, depending on the processes used. Where cooling is supplied via district heating, the additional demand for heat represents an opportunity to increase heat revenue.

Cogeneration technologies are run in accordance with heat and electricity revenue. The results of the optimisation of operations in CHP plants show that the electricity price is only high enough to cover variable costs independently of heat revenue during a few hours per year. This means that grid-bound CHP plants in particular are only run for a limited number of hours in the summer. Increased heat demand in summer would therefore increase the full-load hours of CHP plants and in turn reduce specific costs.

In heating grids with must-run technologies, however, a large proportion of heat demand in the summer months is already covered by cheap waste heat, reducing the likelihood of cogeneration being used. Furthermore, it should be noted that from an economic perspective, under the assumptions made here the supply of cooling via district heating is not more cost-effective than cooling via air conditioning systems, even if the heat is provided free of charge. In addition, in the central scenario there is no economic potential for additional heat revenue through the supply of cooling.

6.6.3 Economic potential for district cooling

Another option for the supply of cooling is centralised generation and distribution via a district cooling grid. In this case, the geographical features of a region have a major impact on technical and economic potential. An analysis of existing district cooling grids shows that it may be appropriate to establish such grids under certain conditions.

Due to the required cooling loads and the spread of buildings with sufficient full-load hours for application of district cooling, nationwide district cooling grids are very uneconomical. The line between district cooling grids and district-heating-based cooling is a fine one. In practice, what is referred to as district cooling plants are often constructed. These are plants that mostly generate cooling using district-heating-bound absorption chillers in combination with compression chillers for individual, very large buildings or building complexes. If several such buildings are located in close proximity, they can be connected via a district cooling grid.

6.7 Estimation of primary energy savings and reductions in greenhouse gases

6.7.1 Methodology

On the basis of the most cost-effective technology mix identified, the required primary energy quantity and composition to cover the additional economic potential for district heating and cogeneration is calculated. This information is then used to calculate emissions. The primary energy consumption and emissions determined are compared with the primary energy consumption and emissions of a reference technology. In the area of households and businesses, a local gas boiler is used as a reference technology. If a region is not connected to the gas grid, an oil boiler is used instead. Primary energy savings and emissions reductions in the given scenario compared to the reference technology are then calculated. In doing so, the temperature-adjusted efficiency reference values in accordance with Commission Implementing Decision 2011/877/EU are used (see Section 6.3.4). This results in an efficiency value of 90.6 % for gas boilers and 89.6 % for oil boilers. In industry, a comparison is made with the most common technology for pure heat supply, or if cogeneration plants are already the only technology in use, with a gas boiler. If economic potential is found for recovery boilers with steam turbines, no primary energy savings are shown for the plants in question. In this case, the liquor is incinerated on-site for use in other processes. This technology has a poor energy performance. Emissions are calculated using the emissions factors set out in Table 6-3. The emissions generated as a result of the additional potential for cogeneration technologies are calculated on the basis of fuel consumption for both electricity and heat, and not separately. For grid-bound technologies, emissions produced by the peak load boiler are taken into account. For the reference technology, it is assumed that the volume of electricity generated is produced separately by power stations. Electricity-controlled cogeneration is used when electricity prices are high, which forces fossil fuel power stations out of the merit order. In order to calculate the primary energy used to generate electricity for the reference technologies, the overall energy performance of fossil fuel power stations in line with the modelled electricity generation for 2025 for the shared Austrian-German market is used. This is calculated by dividing total generation by total primary energy use, and amounts to 42.1 %. The emissions produced by the reference technologies as a result of electricity generation are then calculated based on average fossil fuel emissions, which stand at 0.844 tCO_2e/MWh_{el}.

In industry, due to the inclusion of industrial waste material, more than one fuel is used for certain technologies. In these cases, the emissions are calculated in line with the share of each fuel in total energy consumption.

6.7.2 Results of the calculation of primary energy savings and greenhouse gas reductions for households and businesses

On the basis of the additional economic potential determined for district heating and cogeneration, reductions/increases in primary energy consumption and greenhouse gas emissions can be calculated and compared to reference technologies, as seen for households and businesses in Table 6-7. The savings indicated here refer to the additional economic potential, and do not serve as a comparison with current emissions values.

Table 6-7: Primary energy savings and greenhouse gas reductions arising from the additional economic potential for district heating and cogeneration for households and businesses in the central scenario

Region	**Primary energy savings in GWh / a primary energy**		**Emissions reductions in thousand tCO_2e / a**	
	District heating	**Of which cogeneration**	**District heating**	**Of which cogeneration**
Vienna	-340	0	-30	0
Graz	-10	0	40	0
Linz	590	0	110	0
Salzburg	30	0	30	0
Innsbruck	-120	0	-20	0
Dornbirn	-50	0	10	0
Klagenfurt	-90	0	0	0
Remaining primary regions	-80	0	310	0
Secondary regions	-1180	0	3180	0

In the central scenario, among the regions analysed in more detail, positive energy savings can only be identified in Linz and Salzburg. The greatest savings are achieved in Linz as a result of a large proportion of industrial waste heat as well as a small proportion of biomass heating plants. In all of the other regions/groups of regions listed in Table 6-7, primary energy consumption in the event of exploitation of the economic potential is higher than in the reference case. This is due in particular to the high economic potential for district heating with a large number of centralised gas boilers. Due to the heating grid losses of 10 %, the use of centralised gas boilers results in higher primary energy consumption than the use of building-related gas boilers.

Emissions vary depending on the energy source used. Thanks to the substantial economic potential for biomass in the remaining primary regions and in the secondary regions in particular, this is where the greatest emissions reductions are achieved. Over 86 % of these reductions are attributable to the secondary regions.

As there is no economic potential for cogeneration under the given conditions, there are no primary energy savings or greenhouse gas reductions resulting from cogeneration either.

6.7.3 Results of the calculation of primary energy savings and greenhouse gas reductions in industry

In industry, primary energy savings can be achieved through the use of (high-efficiency) cogeneration. The results of the calculation of primary energy savings and greenhouse gas reductions in industry, based on the economic potential for cogeneration, can be found in Table 6-8. The savings indicated here refer to the additional economic potential, and do not serve as a comparison with current emissions values.

Table 6-8: Primary energy savings and greenhouse gas reductions arising from the additional economic potential for cogeneration in industry in the central scenario

Region	Primary energy savings in GWh/a primary energy	Emissions reductions in thousand tCO_2e/a
Pulp and paper	0	500
Wood industry	253	280
Chemicals industry	0	0
Food materials industry	0	0
Manufacture of machinery and equipment n.e.c.	0	0
Vehicle construction	0	0

In industry, there is economic potential for cogeneration in the paper and pulp sector and in the wood industry. In the paper and pulp sector, this concerns potential for the use of recovery boilers with steam turbines, and in the wood industry this concerns potential for the use of fluidised bed boilers with steam turbines.

In the paper and pulp industry, no primary energy savings are achieved for companies with economic potential for recovery boilers with steam turbines, as the liquor is primarily used in other processes on-site.

In the wood industry, primary energy consumption is reduced by the potential for fluidised bed boilers with steam turbines, which have a very high overall efficiency rate.

As emissions from recovery boilers with steam turbines are defined as zero, they necessarily fall below the emissions from the reference technology. In the wood industry, primarily biomass is used, meaning that no emissions are produced here either. In the case of separate production of heat and electricity, however, the fluidised bed boilers used as a reference technology for heat supply do not produce any emissions either if they use biomass. Therefore, when calculating the greenhouse gas reductions, fossil fuel power stations are used as a reference technology for covering the electricity not generated by industrial cogeneration.

6.8 Sensitivity analysis

Below, the sensitivity of the results of the economic potential analyses for district heating and cogeneration under Sections 6.4 and 6.5 is assessed. The following sensitivity scenarios are examined:

- high CO_2 price of 100 EUR/tCO_2
- low gas price of 20 EUR/MWh
- high gas price of 40 EUR/MWh
- low connection rate of 45 %
- high efficiency in the building stock and in industry.

The high efficiency scenario concerns the implementation of energy efficiency measures in the building stock and in industry resulting in reduced heat demand. The low connection rate scenario refers to the number of consumers connected to the district heating grid, and therefore applies only to the potential analysis for households and businesses.

6.8.1 Impact of the sensitivity scenarios on the input parameters

The sensitivity analyses for a high **CO_2 price** and for a high/low gas price take account of the effect of this on the electricity price curve and therefore on the electricity revenues of CHP plants. The changed prices affect the marginal costs of the power plants, thereby leading to a change in the merit order for the electricity market. A high CO_2 price leads to proportional increases in the costs of coal-fired power stations, meaning that gas-fired power stations gain a cost advantage. However, compared to CO_2-free technologies such as biomass-fired power stations, local biomass boilers or heat pumps, natural-gas-fired technologies are less cost-efficient.

A change in the **gas price** affects the electricity price on the one hand, and the fuel costs for gas-fired technologies on the other. A rising average electricity price is therefore accompanied by a rise in fuel costs and vice versa. In the case of natural gas prices for end customers (households, businesses, industry), the increase in fuel costs is calculated on the basis of the absolute change in the natural gas spot price. Other components of end customer prices such as network charges are regarded as constant.

A reduction in the **grid connection rate** in non-grid-connected sub-regions leads on the one hand to a drop in demand that can be covered by grid-bound technologies.

On the other hand, this also results in a fall in absolute distribution grid costs due to the reduction in costs for the connection of houses and for the household connection lines, including operating and maintenance costs. As the other distribution grid costs are spread across fewer consumers, there is a rise in specific distribution grid costs. The transmission costs are based on a specified reference capacity, and are therefore unaffected by the grid connection rate.

In the **efficiency scenario**, heat demand is reduced through implementation of energy efficiency measures. This leads to lower heat demand per area, and therefore to lower heat densities, which causes network costs to rise. Furthermore, it is possible to cover a larger proportion of total heat demand within a region using existing capacity.

6.8.2 Sensitivity of the results of the potential analysis for households and businesses

The diagram in Figure 6-9 depicts the economic potential for district heating at a connection rate of 45 %, broken down by region. Here, the bottom end of the range of economic potential is clearly defined at a connection rate of between 45 % and 90 %.

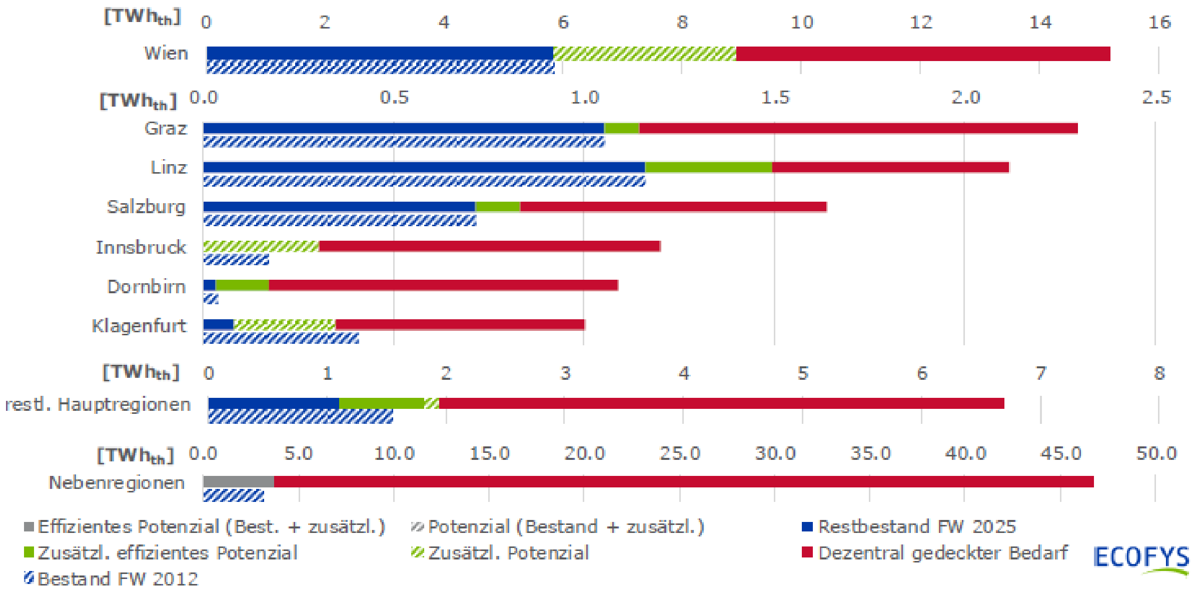


Figure 6-9: Heat supplied via district heating in 2012, heat supplied by existing district heating in the 2025 scenario and (efficient) economic potential for district heating in 2025 in the 45 % connection rate scenario

Wien	Vienna
Restl. Hauptregionen	Remaining primary regions
Nebenregionen	Secondary regions
Effizientes Potenzial (Best. + zusätzl.)	Efficient potential (existing + additional)
Zusätzl. Effizientes Potenzial	Additional efficient potential
Bestand FW 2012	Existing district heating in 2012
Potenzial (Bestand + zusätzl.)	Potential (existing + additional)
Zusätzl. Potenzial	Additional potential
Restbestand FW 2025	Remaining district heating in 2025
Dezentral gedeckter Bedarf	Demand covered by decentralised means

In the **low connection rate** scenario with a maximum connection rate of 45 % in the event of further expansion of the district heating grid, the economic potential for district heating proves extremely sensitive. The economic potential for district heating falls by 78 % compared to the central scenario, to 9.0 TWh$_{th}$ per year.

As such, in the regions presented, there is less economic potential for district heating than in the central scenario. However, there is still very little additional potential for district heating in the primary regions presented. The greatest drop in potential compared to the central scenario can be observed in the secondary regions. Due to their reduced district heating potential, in some regions the share of industrial heat, renewable energies or CHP plants rises to such an extent that efficient district heating potential accounts for over 50 % of the total additional district heating potential.

The substantial drop in district heating potential is on the one hand due to the halving of potential consumer connections, and on the other to the resulting increase in specific network costs. Although absolute network costs do fall due to the reduction in house connections, the majority of network costs attributable to the distribution grid within a particular area would have to be spread across a smaller number of consumers. As such, specific network costs increase by 56–89 %, depending on the heat density, meaning that decentralised technologies obtain a substantial cost advantage. At a connection rate of 45 %, and under the assumptions made in this study, the use of district heating to cover heat demand is only the most cost-effective option in areas with high heat densities.

Figure 6-10 contains a diagram summarising the results of all of the sensitivity analysis scenarios. The economic potential in the various scenarios is compared to the results for the central scenario. The diagram depicts both heat supply from existing capacity in 2025 and economic potential for district heating and cogeneration. As regards district heating supply from existing capacity, this can vary, as the operating mode for existing plants depends on heat demand and, in the case of cogeneration, on developments in fuel and electricity prices.

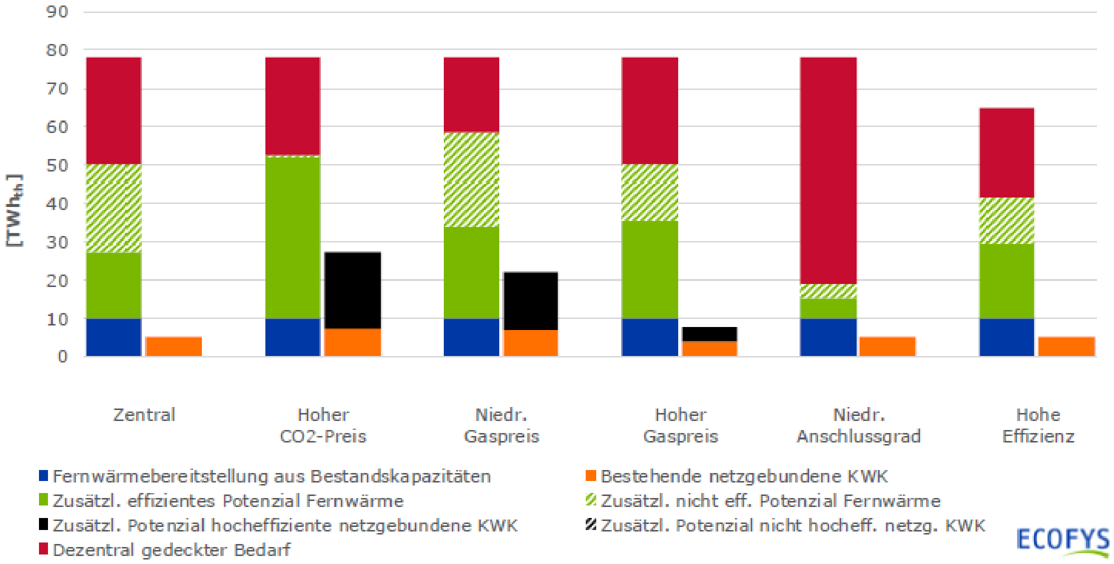


Figure 6-10: Sensitivity of the results for households and businesses to the parameters examined

Zentral	Central
Hoher CO2-Preis	High CO2 price
Niedr. Gaspreis	Low gas price
Hoher Gaspreis	High gas price
Niedr. Anschlussgrad	Low connection rate
Hohe Effizienz	High efficiency
Fernwärmebereitstellung aus Bestandskapazitäten	District heating from existing capacity
Zusätzl. Effizientes Potenzial Fernwärme	Additional efficient potential for district heating
Zusätzl. Potenzial hocheffiziente netzgebundene KWK	Additional potential for high-efficiency grid-bound cogeneration
Dezentral gedeckter Bedarf	Demand covered by decentralised means
Bestehende netzgebundene KWK	Existing grid-bound cogeneration
Zusätzl. Nicht eff. Potenzial Fernwärme	Additional non-efficient potential for district heating
Zusätzl. Potenzial nicht hocheff. Netzg. KWK	Additional potential for non-high-efficiency grid-bound cogeneration

Figure 6-10 demonstrates that changes in the individual parameters and assumptions has an impact on the economic potential for district heating and cogeneration as well as on the share of efficient district heating and high-efficiency cogeneration in total energy demand.

A **high CO_2 price** of 100 EUR/tCO_2 leads to a sharp rise in CO_2 costs, which causes an increase in the costs of gas-fired technologies in particular.

In addition, an increase in the CO_2 price on the electricity market leads to changes in the merit order. The electricity generation costs for fossil fuels increase substantially, whereby the costs for coal- and oil-fired power stations rise proportionally more than those for gas-fired power stations, causing the latter to climb upwards in the merit order. Overall, a clear rise in the wholesale electricity price to over 100 EUR/MWh_{el} on average can be observed. As a result, the revenue of CHP plants and the operating hours of electricity-controlled gas CHP plants both increase.

This leads to high-efficiency cogeneration potential of 19.9 TWh_{th} per year, and an increase in production from existing CHP plants of 52 %. The economic potential for district heating only increases by 5.2 % compared to the central scenario, whereby a large proportion of district heating in this scenario is produced via cogeneration, which replaces other technologies. Thanks to the large share of district heating potential accounted for by cogeneration and biomass, it can be regarded as efficient in nearly all regions. Unexploited technical potential can primarily be found in the secondary regions, as decentralised supply is still more cost-effective than district heating in areas with very low heat densities due to the high network costs, despite the substantially improved conditions.

A change in the **gas price** affects the fuel costs for gas-fired heat supply technologies. It also influences the electricity price due to the change in the fuel prices paid by gas power stations. At a low natural gas price of 20 EUR/MWh, the average electricity price falls to 41.9 EUR/MWh_{el}, and at a high natural gas price of 40 EUR/MWh, it rises to an average of 50.2 EUR/MWh_{el}.

In the **low gas price scenario**, the proportion of economic potential accounted for by non-efficient district heating grows. The additional economic district heating potential stands at a total of 48.6 TWh_{th} per year. This increase is largely down to a rise in the district heating potential in secondary regions, as the low natural gas price gives centralised gas boilers an advantage over decentralised biomass boilers, which are more cost-efficient under the central scenario. The increased use of natural gas in the secondary regions reduces the proportion of efficient district heating grids in those regions. Furthermore, there is an increase in the economic potential for cogeneration, as falling fuel costs per unit of heat generated leads to greater cost reductions in gas cogeneration plants than in the case of gas boilers due to the low thermal efficiency rate of the former. The resulting increase in cogeneration potential in the primary regions, however, brings about a rise in the number of efficient district heating grids. It should be noted here that the differences in prices between centralised gas boilers and gas cogeneration plants are sometimes very marginal, meaning that the results are extremely sensitive to small changes in fuel prices.

In the **high gas price scenario**, the economic potential for district heating is roughly the same, proportionally, as in the central scenario. However, the higher generation costs incurred by gas-fired technologies means that the potential of biomass technologies is greater, thereby increasing the share of efficient district heating. The rising fuel costs for gas power stations also result in economic potential for biomass cogeneration, meaning that the share of cogeneration in total energy demand grows, despite a fall in generation from existing gas cogeneration.

In the **high efficiency** scenario, total heat demand is lower due to a reduction in the heat consumption of buildings. At connection rates of over 90 %, the demand per region that can be covered by district heating falls. In some regions, this means that total heat demand in this scenario is lower than the economic potential calculated for the central scenario. This results in less economic potential for district heating overall. The share of district heating in total heat demand, however, remains more or less constant at around 65 %.

The **sensitivity of primary energy savings** in the area of households and businesses for the various scenarios can be observed in Table 6-9.

Table 6-9: Primary energy savings arising from the additional economic potential for district heating in households and businesses in GWh of primary energy per year

Region	Central	High CO_2 price	Low gas price	High gas price	Low connection rate	High efficiency
Vienna	-340	12,470	10,570	-310	200	-80
Graz	-10	1640	1380	-50	90	40
Linz	590	1050	950	650	330	430
Salzburg	30	1220	1020	0	50	60
Innsbruck	-120	1650	1390	-120	-30	-100
Dornbirn	-50	1480	1240	-80	40	-30
Klagenfurt	-90	1320	1100	-80	-40	-80
Remaining primary regions	-80	7430	5980	-80	170	-20
Secondary regions	-1180	2090	-430	-1900	530	-800

As demonstrated, primary energy savings in the high CO_2 price and low gas price scenarios are far greater than in the central scenario. In both scenarios, the greatest economic potential lies with cogeneration. Relatively high primary energy savings result from the replacement of fossil fuel electricity power stations with combined generation of heat and electricity at a greater overall efficiency rate. High energy savings can be observed in Vienna in particular, thanks to the substantial economic potential for cogeneration and the high heat demand compared to other regions. In the secondary regions, there is much less economic potential for cogeneration due to the lower heat density and limited demand for additional installed capacity, meaning that little to no primary energy savings arise in the high CO_2 price or low gas price scenarios.

The **sensitivity of greenhouse gas reductions** in the area of households and businesses for the various scenarios can be observed in Table 6-10.

Table 6-10: Reduction in CO2 emissions arising from the additional economic potential for district heating in households and businesses in thousand tCO2per year

Region	Central	High CO_2 price	Low gas price	High gas price	Low connection rate	High efficiency
Vienna	-30	8730	7120	-20	80	20
Graz	40	1150	930	70	20	50
Linz	110	520	430	120	70	90
Salzburg	30	850	690	50	20	30
Innsbruck	-20	1160	940	-10	0	-10
Dornbirn	10	1070	860	40	30	10
Klagenfurt	0	940	750	10	10	10
Remaining primary regions	310	5310	4080	410	140	290
Secondary regions	3180	6220	2430	3940	830	3200

A similar picture as for primary energy savings emerges for reductions in greenhouse gases in the various scenarios, as the amount of primary energy savings affects emissions. However, the use of regenerative energy sources has a clear impact. Due to the large share of biomass in the secondary regions in particular, positive, relatively high reductions can be observed across all scenarios. Reductions can also be observed in the central, high gas price and high efficiency scenarios, despite increased primary energy consumption.

6.8.3 Sensitivity of the results of the potential analysis in industry

Figure 6-11 contains a diagram summarising the results of the sensitivity analysis for industry. For each sensitivity scenario, the additional economic potential for cogeneration across all sectors is compared to production from existing cogeneration capacity.

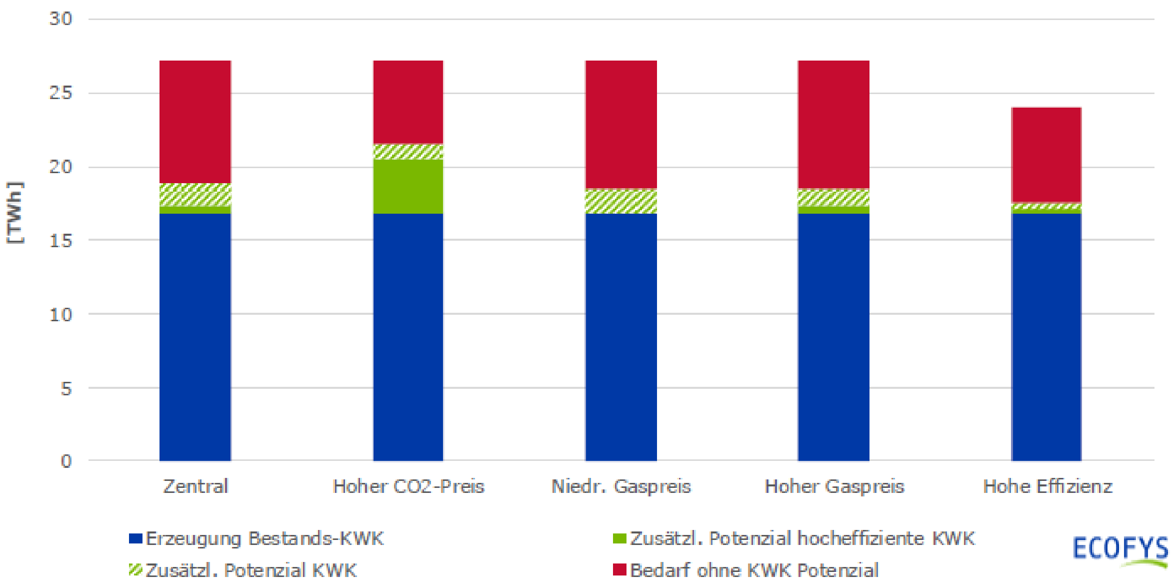


Figure 6-11: Sensitivity of cogeneration potential in industry to the parameters examined

Zentral	Central
Hoher CO2-Preis	High CO2 price
Niedr. Gaspreis	Low gas price
Hoher Gaspreis	High gas price
Hohe Effizienz	High efficiency
Erzeugung Bestands-KWK	Generation from existing CHP plants
Zusätzl. Potenzial KWK	Additional potential for cogeneration
Zusätzl. Potenzial hocheffiziente KWK	Additional potential for high-efficiency cogeneration
Bedarf ohne KWK Potenzial	Demand without cogeneration potential

At a **high CO2 price** of 100 EUR/tCO_2, cogeneration potential rises in the paper and pulp sector and in the chemicals industry. The increase in the price of CO_2 results in an increase in the wholesale electricity price, meaning that cogeneration plants can generate more revenue from electricity. This is particularly true of cogeneration plants with high electrical efficiency, such as gas and steam power stations. As a result, in the paper and pulp industry, gas and steam power stations gain a cost advantage compared to gas boilers, increasing the cogeneration potential in this sector of industry to 100 %. Gas and steam power stations also offer economic potential in the chemicals industry. Due to the high heat demand from companies in the chemicals industry, major growth in cogeneration potential can be observed in the high CO_2 price scenario. The increased use of technologies with a good energy performance means that the majority of this potential can be classed as high-efficiency.

The sensitivity scenarios involving a change in the gas price only affect economic potential for cogeneration in the wood industry. At a **low gas price** of 20 EUR/MWh, the economic potential for cogeneration shrinks, as in the panel production sector fluidised bed boilers used purely for heat generation are more cost-efficient than fluidised bed boilers with steam turbines, as examined in the central scenario. This is due in particular to the slight drop in the electricity price caused by the reduced natural gas price. In the wood processing sector on the other hand, which accumulates only a small number of full-load hours, the economic potential for cogeneration increases as the use of boilers with steam turbines is the most cost-effective option due to the low natural gas price and low investment costs.

In the **high gas price** scenario with a natural gas price of 40 EUR/MWh, the economic potential for cogeneration is also slightly reduced compared to the central scenario. Due to the high fuel costs for natural gas, solely biomass-fired plants are used in the wood industry. In both panel production and wood processing, the use of cogeneration plants in all or part of the sector is the most cost-effective option.

In the **high efficiency** scenario, heat demand is lower than in the central scenario. In the paper and pulp industry, demand rises only slightly above current heat demand. The minor increase in the quantity of black liquor produced can be co-incinerated in existing recovery boilers with steam turbines. Furthermore, in this scenario gas-fired cogeneration technologies do not demonstrate any economic potential in the paper and pulp industry due to the negligible amount of additional capacity required. In the wood industry, there is no change in the most cost-effective technologies. The absolute potential for cogeneration is 9 % lower due to the greater reduction in heat demand compared to the central scenario.

The **sensitivity of primary energy savings** in industry to the scenarios examined can be observed in Table 6-11.

Table 6-11: Primary energy savings arising from additional economic potential for cogeneration in industry in GWh primary energy per year

Sector	Central	High CO_2 price	Low gas price	High gas price	High efficiency
Pulp and paper	0	1086	0	0	0
Wood industry	253	253	0	256	195
Chemicals industry	0	2932	0	0	0
Food materials industry	0	0	0	0	0
Manufacture of machinery and equipment n.e.c.	0	0	0	0	0
Vehicle construction	0	0	0	0	0

In the paper and pulp sector, the use of gas and steam power stations brings about primary energy savings in the high CO_2 price scenario. In all other scenarios, the economic potential for cogeneration is dependent on the use of recovery boilers with steam turbines, meaning that no primary energy savings are achieved.

In the wood industry, primary energy savings remain largely constant across all scenarios. It is only in the low gas price scenario that primary energy savings fall in this sector due to the major reduction in economic potential for cogeneration.

In the high CO_2 price scenario, there is also economic potential for cogeneration in the chemicals industry, which leads to substantial primary energy savings: almost 17 times more than in the central scenario.

The **sensitivity of greenhouse gas reductions** in industry for the various scenarios can be observed in Table 6-12. In the paper and pulp industry, the use of black liquor can bring about major reductions in greenhouse gas emissions. As a result, in the central scenario around two thirds of the reductions are attributable to the paper and pulp industry. In the wood industry and the chemicals industry, the reductions in emissions are proportional to primary energy savings, whereby the chemicals industry has less of an impact in the high CO_2 price scenario due to the proportionally large savings made through use of biomass in the wood industry.

Table 6-12: Reduction in CO_2 emissions arising from the additional economic potential for cogeneration in industry in thousand tCO_2e per year

Sector	Central	High CO_2 price	Low gas price	High gas price	High efficiency
Pulp and paper	500	1110	500	500	0
Wood industry	280	280	0	280	210
Chemicals industry	0	1650	0	0	0
Food materials industry	0	0	0	0	0
Manufacture of machinery and equipment n.e.c.	0	0	0	0	0
Vehicle construction	0	0	0	0	0

7 Constraints and non-quantified aspects

When interpreting and evaluating the results of the technical and economic potential analyses in this report, it is important to bear in mind that there are a number of constraints preventing exploitation of the economic potential in certain circumstances. Furthermore, it was not possible to include some factors and aspects in the quantitative analysis, e.g. the economic value of various technologies as hedging instruments for reducing economic risk or the evaluation of air pollutants. This section points out these aspects and constraints and discusses their possible implications.

7.1 Analysis of constraints

This section discusses possible barriers to exploiting the potential of high-efficiency cogeneration and efficient district heating and cooling and a number of recommendations on how to increase the share of cogeneration, district heating and district cooling.

7.1.1 Factors influencing economic potential and constraints arising as a result

As part of the economic potential analysis (see Section 6), the most cost-effective technology mix for the supply of heat and cooling to households and businesses was determined, on the basis of which the economic potential for cogeneration and district heating was calculated. Subsequently, the economic potential of cogeneration in industry was also examined.

In Section 6.8, the results were tested for sensitivity to the following input parameters:

- connection rate
- CO_2 price
- gas price and
- demand (efficiency scenario).

In the modified CO_2 and gas price scenarios, a change in the electricity price was also indirectly taken into consideration.

The sensitivity analysis shows that connection rate in particular has an influence on the economic potential for district heating. In Austria, district heating grids face competition mainly from existing gas grids. Moreover, existing buildings are usually only connected to a district heating grid once the technical lifetime of the existing building-related heat supply technology has come to an end, meaning that the connection rate only rises slowly following establishment of the grid. It should also be borne in mind that there are additional hurdles to be overcome when connecting buildings without centralised heat distribution. The often low connection rate upon commissioning of a district heating project and uncertainty surrounding future developments may put substantial constraints on economic potential, as district heating providers may be faced with major delays and uncertainties as regards repayment of their investment in the heating grid.

The CO_2 price and fuel prices also have an impact on economic potential, particularly for cogeneration. Fuel price developments can have either a direct impact (gas and biomass) or an indirect impact via the electricity market (coal) on the economic potential of cogeneration and district heating. An increase in the CO_2 price to 100 EUR/tCO_2 would, in addition to the consequences examined, also affect investments in technologies in the electricity sector, which was not taken into account in the electricity price model. A particularly likely consequence would be an increase in the use of renewables, which would become the preferred option on the electricity market. Furthermore, this would probably have an impact on energy demand.

On top of the varying input parameters studied here, there are also additional factors that may impact economic potential.

Heat supply via district heating is **grid-bound** and depends on local heat demand. Unlike in the electricity sector, centralised heat supply serves a small market, and is therefore subject to more uncertainty and risks. Structural changes on the ground may affect heat density and in turn specific distribution grid costs. This means that for heat supply via heating grids in particular, there is a risk that local demand will fall or will be subject to structural changes (e.g. load peaks). This factor affects investment security for power plant operators, and therefore exploitation of the economic potential. Furthermore, the grid-bound nature of the technology means that it is dependent on local price restrictions. In some regions in Austria, operators are not free to set the price of district heating. Instead, these prices are set at regional level, meaning that it is not always possible to run the power station and the district heating grid cost-effectively as their income from heating is too low. This also results in a long-term risk that it may not be possible to offset unexpected rises in generation costs by increasing the price of district heating.

The cost-effectiveness of CHP plants depends heavily on developments on the electricity market. If there are sufficient incentives on the electricity market side, CHP plants are run in an **electricity-controlled** operating mode. This is only possible if district heating is covered by back-up capacity and/or can be provided flexibly using storage systems, so as to ensure that heat demand is covered at all times. Without sufficient back-up, CHP plants still have to be run when electricity prices are low or even negative if heat demand is also high. Any increases in the amount of time during which electricity prices are low or negative can increase the risk of having to run power stations in this uneconomical manner. In the event of price fluctuations, therefore, increases in back-up capacity or the installation of thermal storage systems may gain in importance. The economic relationship between CHP plant capacity and back-up capacity may change in future, and is heavily dependent on developments on the electricity market. Changes in the electricity price in Austria are, in turn, largely influenced by the German market.

If a surplus quantity of electricity is generated, **power-to-heat** plants that transform electricity into heat by way of heat pumps or electrode boilers, for example, may represent a suitable supplement to CHP plants.

Furthermore, **technical restrictions** to power plant parameters may have an adverse effect on economic potential. CHP plants in particular must increasingly be able to respond flexibly to heat demand and electricity prices. Due to the relatively minor fluctuations in the electricity price and in heat demand, however, these restrictions remain minimal at the current time. Furthermore, strict technical requirements are in place for the construction of power plants when it comes to emissions. Preventing or reducing emissions represents a major cost factor when constructing a power plant, and increases investment costs accordingly. Decentralised heat supply technologies, on the other hand, are subject to less stringent requirements, meaning that they tend to gain a cost advantage.

Economic potential is also dependent on **developments in the cost** of other competing technologies. In the field of heating, however, most technologies are already highly advanced. The greatest potential for reducing costs lies with heat pumps and, under certain circumstances, solar thermal energy.

7.1.2 Barriers to the exploitation of economic potential

In addition to the influencing factors that reduce economic potential itself, there are also barriers that limit the exploitation of available economic potential. These barriers can be of a financial or of a social nature.

Investment security has an influence on the implementation of business projects. Major projects in particular, such as the installation of a district heating grid or the construction of a large centralised heating plant, are associated with uncertainties with regard to long-term cost-effectiveness and to planning permission, which may not be forthcoming for several years. The lifetime of these projects, and as such the planning period, is very long, meaning that projects are heavily exposed to long-term, unpredictable changes in certain parameters such as fuel prices, heat demand and electricity prices in the case of cogeneration plants. In the heat sector, margins are usually small, which means that project risks are high. On the one hand, this risk impedes investments being made in district heating grids. On the other, it also restricts the economic potential of grid-bound cogeneration technologies. Smaller power plants are at an advantage here, as investment amounts are usually smaller, resulting in a reduced level of risk. Conversely, economies of scale are one argument in favour of larger power plant units. Furthermore, it should be explicitly noted at this point that economic potential was calculated on the basis of economic parameters, including an interest rate of 4 %, and taking into account technical lifetimes. Much higher returns are required for business investment decisions to be taken.

Another aspect that may restrict exploitation of the economic potential is **acceptance** of the project among the population. Extending lines within an existing district heating grid does not usually pose a problem. However, there may be objections within the population to the connection of the majority of new consumers to an extended or new district heating grid. Some consumers regard connection to a district heating grid as rendering them dependent on grid-bound supply. Furthermore, consumers may refuse connection to the grid if the decentralised supply technology they are currently using has not yet reached the end of its technical lifetime. In addition, the construction of new (especially fossil fuel) power stations is coming up against increasing resistance among the population. The need for the power station to be located in close proximity to consumers reinforces opposition to such projects.

As with other grid-bound technologies, centralised heat supply via a district heating grid results in mutual **dependency of the parties involved**, and thereby represents a risk for all parties. This dependency means that a relationship of trust is required in order to allow successful cooperation. However, this does not only apply to the consumption side: it also applies in particular in the case of industrial waste heat. Often, the use of industrial waste heat is rendered impossible by the lack of such a relationship of trust.

There are also specific constraints that apply to the supply of heat via industrial waste heat. The fact that the **waste heat is process-related** may mean that efficiency gains in the process directly affect the potential for waste heat. Here, the question is how long industrial waste heat will be available to cover heat demand via a district heating grid. In addition to efficiency gains, other business-related factors may reduce capacity utilisation and thereby the volume of heat produced.

7.1.3 International legislative environment for promoting the exploitation of economic potential

By way of various Directives, the European Commission has set targets for the European Union in terms of energy efficiency and the share of renewables in the energy mix. In most cases, Member States themselves are responsible for deciding which measures and instruments to use in order to meet those targets. The measures and instruments implemented by the Member States have an impact on the share of total energy demand accounted for by district heating and cogeneration. In addition, certain countries have created further-reaching legal frameworks to encourage exploitation of the economic potential for district heating and cogeneration.

At **European level**, the Renewable Energy Directive (Directive 2009/28/EC) stipulates that 20 % of end energy consumption in the EU must be covered by renewable energy by 2020 (15.5 % in the heating/cooling sector), whereby individual targets are specified for each Member State.

The Energy Performance Directive (Directive 2010/31/EU) sets out minimum energy performance requirements for new buildings and extensive renovation work carried out on existing buildings. In this case, Member States must ensure that decentralised energy supply using renewable energy, cogeneration, district heating and cooling and heat pumps is taken into account. Furthermore, the Member States must ensure that as of 1 January 2021, all new buildings are 'zero-energy buildings' with an energy demand of near zero. A large proportion of this low level of energy demand is intended to be covered by decentralised or locally produced energy from renewable sources. This may impact regional energy demand, the demand load profile and the share of renewable energy sources.

The EU Energy Efficiency Directive (Directive 2012/27/EU) contains measures to achieve the objective of reducing primary energy consumption in the EU by 20 % compared to country-specific projections between now and 2020. An obligation is imposed on Member States to make annual savings of 1.5 % of average energy sales from 2010–2012 between 2014 and 2020. Member States are free to choose the instruments and measures to achieve this target.

In accordance with the Renewable Energy Directive, **Germany** has specified measures to increase the share of renewable energy sources in heat supply by way of the Renewable Energy in Heating Act [*Erneuerbare-Energien-Wärmegesetz*, EEWärmeG]. The EEWärmeG lays down a minimum percentage of heat demand to be covered by renewable energy sources in new buildings. This share varies depending on the energy source used. The percentage of heat demand that must be covered stands at 15 % for solar energy, 30 % for gaseous biomass and 50 % for fluid and solid biomass as well as geothermal and ambient heat.

As an alternative measure, 50 % of heat or cooling demand can also be covered by waste heat or by high-efficiency cogeneration. Another alternative is to cover heat demand using district heating, but in this case a substantial proportion of the heat must be produced using renewable energy, namely 50 % from systems using waste heat, 50 % from CHP plants or 50 % from a combination of the two. The use of district heating and CHP plants is therefore an option for meeting legal obligations if the specified criteria are adhered to. The requirements have an adverse effect on the economic potential calculated for decentralised and centralised gas boilers in particular, as they do not meet these criteria, or only meet the criteria in combination with other technologies. For district heating grids, an incentive is also introduced to integrate technologies that must be used for such grids to be classed as efficient so that new buildings can be connected to the district heating grid.

Furthermore, Germany provides support for measures concerning the use of renewable energy on the heating market. With an envelope of EUR 300 million per year, the market incentive programme introduced in 2015 is primarily aimed at providing funding for the modernisation of existing buildings and commercial and industrial processes. On the one hand, subsidies are provided for investments in smaller systems in households and businesses, and on the other low-interest loans and repayment bonuses are offered by the German Reconstruction Loan Corporation [*Kreditanstalt für Wiederaufbau*, KfW] for large commercial systems. This support goes towards systems using renewable energy sources and heating grids supplied with heat generated from renewables.

Worldwide, **Denmark** is one of the countries with the highest coverage of heat demand through district heating. 63 % of all heat consumers are supplied via district heating, and 52 % of district heating is generated using renewable energy (Dansk Fjernvarme, 2014). Furthermore, 72 % of district heating is produced in CHP plants (Danish Energy Agency, 2015). The large share of district heating is a result of the substantial support provided to municipalities. To this end, district heating is seen alongside the supply of water, waste collection and other services as an integral part of urban utilities.

In accordance with Section 4 of the Danish law *Bekendtgørelse om godkendelse af projekter for kollektive Varmeforsyningsanlæg*, municipalities must draw up a plan for the supply of heat in their catchment area. In accordance with Section 7, this excludes the installation of district heating and natural gas grids. In accordance with Section 1 of the Danish Heat Supply Act [*Bekendtgørelse af lov om varmeforsyning*], the most cost-effective technology must be identified and used when drawing up the heat supply plan. It should be noted at this point that Denmark applies high tax rates to fossil fuels, meaning that the use of renewables-based technologies is on the rise.

Almost all district heating companies in Denmark are consumer-owned, either directly by consumer cooperatives or indirectly by the municipality. The companies' profits are either passed on directly to consumers at the end of the year, or are translated into lower heat prices the following year. The high degree of investment security for projects thanks to the stable policy environment in the heat sector and the furnishing of credit guarantees by the municipalities (including for consumer cooperatives) enables projects to be financed at favourable conditions (DBDH 2015). Furthermore, the Danish Heat Supply Act stipulates that for district heating projects that have already been approved, the municipality council may introduce an obligation for new buildings, and for old buildings depending on their technical lifetime, to connect to district heating grids.

This review of the international legislative environment demonstrates firstly that national laws are being adopted in order to meet EU requirements. Secondly, it shows that national laws sometimes go above and beyond these requirements and promote particular aspects of heat supply such as district heating or the use of renewables. In performing their targeted reorganisation of the heating sector, countries rely on legal provisions, financial support in favour of certain technologies or the taxation of individual energy sources. Countries tend to subsidise portfolios containing a range of heat supply technologies rather than the use of individual technologies.

7.2 Non-quantified aspects of district heating and cooling

Alongside the parameters used to calculate economic potential, the supply of heat and cooling via centralised grids produces additional, primarily positive effects that could not be quantified in the calculations as they are associated with a high degree of uncertainty. These effects are described in more detail below.

7.2.1 Available flexibility for integration of fluctuating renewable energy sources

The interaction between district heating and events on the electricity market results in synergies that may facilitate the integration of renewable energy sources. For example, electric boilers or heat pumps can be used to supply heat in the event of future surpluses resulting from photovoltaic energy or from peaks in wind power generation. This reduces the cost of supplying heat, and increases the market value of renewable energy sources on the electricity market. In addition, cogeneration technologies can efficiently provide electricity at times of lower capacity utilisation as well as contributing to covering peak loads. The district heating power station fleet can also be used to provide balancing energy to maintain voltages. While all of these advantages do, in principle, also apply to decentralised technologies (micro-cogeneration, decentralised heat pumps etc.), there is usually only one technology available to cover each individual heat load (resulting in far less flexibility) and most of these technologies are not currently controlled in line with the conditions on the electricity market.

These aspects could not be entirely quantified in the context of this study, which should be taken into account when interpreting the results.

7.2.2 District heating as a hedging instrument: reduced price risk through diversification of supply technologies

If there are several heat supply technologies available within a heating grid, this reduces the price risk for customers compared to decentralised heat supply. If the gas price rises, for example, this could be offset by increased use of heat pumps, preventing the price increases for primary energy sources from filtering through into heat supply costs in their entirety. This is not possible in the case of decentralised production using only one heat supply technology, and costs rise and fall in line with the price of the energy source. This means that on the whole, decentralised heat supply is subject to a greater degree of price risk. This does of course only apply if several heat supply technologies using varying fuel types are available within heating grids.

A precise analysis of risk aspects was not part of the scope of this project. As such, these aspects could not be entirely quantified in the context of this study, which should be taken into account when interpreting the results.

7.2.3 Air pollutants

In this potential analysis, emissions of air pollutants (fine particles (PM10), nitrogen dioxide (NO2), sulphur dioxide (SO2), carbon monoxide (CO)) were not quantified in the calculation of technical potential or in the economic analysis, and are not therefore included in the comparison of the costs of centralised and decentralised technologies. Particularly in the critical areas defined by the Austrian Air Immission Control Act [*Immissionsschutzgesetz-Luft*], but also in built-up areas in general, the use of decentralised biomass heating systems should be regarded in a critical light. The specific emissions produced by larger plants in heating grids are significantly lower if these are operated correctly and if exhaust filters are used. As such, the expansion of heating grids in these regions may contribute to alleviating air pollution (see Gössl et al., 2013). In addition, heat pumps, solar thermal energy and efficient gas-fired condensing boilers can also reduce air pollution.

A more precise comparative analysis of air pollutant emissions was not part of the scope of this project. As such, these aspects could not be entirely quantified in the context of this study, which should be taken into account when interpreting the results.

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11 Annex

11.1 Calculating the heat supply costs

Table 11-1 uses the example of a biomass heating plant to illustrate the proportion of heat supply costs accounted for by the various cost components in a sample district heating grid. Heat supply costs are composed of generation costs and distribution grid costs. Additional transmission costs may also arise, depending on the technology. The individual cost components are converted to provide specific costs per unit of heat. This is based on the following assumptions:

- full-load hours of the heating grid: 2500 h/a
- full-load hours of the biomass heating plant: 4998 h/a
- full-load hours of the peak load boiler: 428 h/a
- capacity of the heating grid: 10 MW_{th}
- connection rate: 90 %

In this example, heat supply costs amount to 70.9 EUR/MWh_{th}. Of this, 44.6 EUR/MWh_{th} (62.9 %) is attributable to generation costs, and 26.3 EUR/MWh_{th} (37.1 %) to distribution grid costs. The generation costs are composed of the weighted costs for the biomass heating plant of 42.2 EUR/MWh_{th} and for the peak load boiler of 66.8 EUR/MWh_{th}.

The greatest share of generation costs is accounted for by fuel costs. However, the proportion accounted for by annualised investment costs may be significantly higher for technologies with high investment costs, but this depends on the depreciation rate for each technology. In the case of cogeneration technologies, electricity revenue must also be included in the calculation. The fuel costs of the biomass heating plant account for more than 40 % of the total heat supply costs.

The distribution grid costs are mostly attributable to investment costs for the distribution grid. A small share is also accounted for by household connection costs, although these are far lower than the annual operating and maintenance costs.

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Table 11-1: Heat supply and distribution grid costs broken down into individual cost components using the example of a biomass heating plant

	Investment costs	Depreciation rate	Annual costs/annuity	Costs per unit of heat	Percentage of total costs
Generation costs					
	EUR/kW$_{th}$	*years*	*EUR/kW$_{th}$/a*	*EUR/MWh$_{th}$*	*%*
Biomass heating plant (90 % of generation)					
Investment	470	20	34.6	6.9	8.8 %
Operating and maintenance costs			14.1	2.8	3.6 %
Fuel costs				32.4	41.1 %
CO_2 costs				0.0	0.0 %
Total				**42.2**	**53.5 %**
Gas boiler to cover peak load (10 % of generation)					
Investment	100	35	5.4	12.6	1.8 %
Operating and maintenance costs			3.7	8.6	1.2 %
Fuel costs				39.4	5.6 %
CO_2 costs				6.1	0.9 %
Total				**66.8**	**9.4 %**
Weighted generation costs					
Investment				7.5	10.6 %
Operating and maintenance costs				3.4	4.8 %
Fuel costs				33.1	46.7 %
CO_2 costs				0.6	0.9 %
Total				**44.6**	**62.9 %**
Distribution grid costs					
	EUR	*years*	*EUR/a*	*EUR/MWh$_{th}$*	*%*
Network costs	7,423,000	30	429,300	19.1	26.9 %
Household connection costs	675,000	30	39,000	1.7	2.4 %
Operating and maintenance costs			121,500	5.4	7.6 %
Pump energy costs			2000	0.1	0.1 %
Total			**591,800**	**26.3**	**37.1 %**
Sum of heat supply and distribution grid costs					
				EUR/MWh$_{th}$	*%*
Total				**70.9**	**100 %**

11.2 Economic potential for district heating in the secondary regions

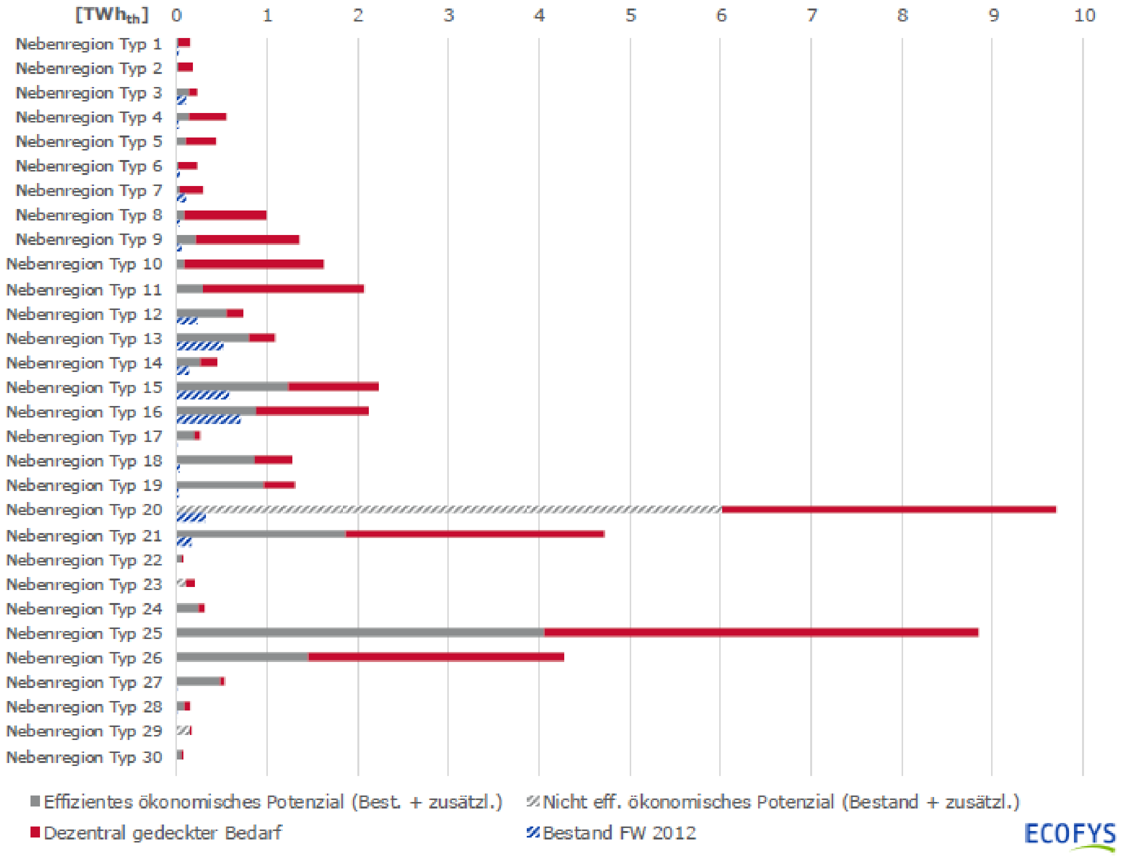

Figure 11-1: Supply of heat via district heating in 2012 and (efficient) economic potential for district heating in 2025 for all secondary regions in the central scenario

Nebenregion	Secondary region
Effizientes ökonomisches Potenzial (Best. + zusätzl.)	Efficient economic potential (existing + additional)
Dezentral gedeckter Bedarf	Demand covered by decentralised means
Nicht eff. Okonomisches Potenzial (Bestand + zusätzl.)	Non-efficient economic potential (existing + additional)
Bestand FW 2012	Existing district heating in 2012

11.3 Involvement of relevant stakeholders

This section aims to provide information about the involvement of stakeholder groups affected by this study. The intention is to document significant milestones in the discussion processes and any discrepancies between the project results and the opinions and standpoints of these stakeholder groups.

Initial contact with relevant stakeholder groups took place during two stakeholder meetings in April 2014 during which the project was presented to two different interest groups, namely industrial energy consumers (7 April 2014) and energy providers (9 April 2014) on the premises of the Ministry for the Economy. With 19 guests representing industrial energy consumers in the various sectors and 14 guests representing energy service providers, it was possible to address a large number of representatives of the most relevant professional groups or energy companies during these two meetings. Discussions primarily centred around the available data and the methodology selected to calculate the technical and economic potential.

On 10 April 2014, part of the project team participated in an expert workshop on 'Challenges to the future development of district heating and cooling in Austria'. During this workshop, which took place in connection with the project 'Development of a district heating and cooling technology roadmap for Austria', the main challenges and problems were systematically addressed.

On 15 April 2014, an initial coordination meeting took place at the Technical University of Vienna between the project team and the project 'STRATEGO – Multi-level actions for enhanced heating and cooling plans'. The STRATEGO project is being conducted by an international consortium with the participation of the AIT, coordinated by Euroheat & Power. The project aims to support the implementation of national heating and cooling plans, the introduction of supporting measures and the transfer of knowledge through communication of examples of best practice and national benchmarking.

On 14 May 2014, the project consortium Joanneum Research, Energie AG Wärme and Geoteam presented the results of the GeoEnergie2050 project at the Technical University of Vienna. In this study, the technical and economic potential of geothermal energy in Austria was examined. The technical potential calculated was used as input data in this project, and the results of the economic potential analyses were used to test the plausibility of the results of the calculation of the economic potential of efficient geothermal-based district heating.

The project was then presented to the Energy Commissioners for the federal states during the KLEA meeting on 27 June 2014 in Linz. The Commissioners were very interested in the data and methodology used, and signalled their openness to participating in discussions and in the validation of results.

On 17 July 2014, a meeting with the 'Österreichs Energie' interest group took place. First, the current power plant fleet and the accompanying technical data were aligned. Then, the information on electricity generation from CHP plants and the share of that generation produced by high-efficiency plants was discussed.

On 23 October 2014, part of the project team participated in an expert workshop on 'Future challenges to Austrian district heating and cooling in terms of education, standardisation and regulatory measures' in connection with the project 'Development of a district heating and cooling technology roadmap for Austria'. During this workshop, aspects of future challenges were examined over the course of several group discussions and brainstorming sessions, to which stakeholders from the various areas contributed.

On 3 December 2014, the second stakeholder workshop in connection with this project took place in the 'Festsaal' room at the Technical University of Vienna, which was attended by 42 guests from industry and the energy services sector. During this workshop, the state of play of the project was presented and discussed. This included a presentation of the data collected, the methodology selected for calculating the technical and economic potential and a transparent discussion of the assumptions that should be made. In addition, this opportunity was used to present the conclusions of the 'SolarGrids' synergy project and of the 'STRATEGO' and 'District heating and cooling roadmap for Austria' projects, with which regular exchanges were held over the entire duration of this project.

During the International Energy Conference [*Internationale Energiewirtschaftstagung*, IEWT] from 11 to 13 February 2015 at the Technical University of Vienna, the methodology and the results of the typology and the classification of primary and secondary district heating regions were presented to an international audience. During the same session, Bernd Eikmeier presented the methodology and results of the German study conducted in accordance with Article 14 of the Energy Efficiency Directive 2012/27/EU. A bilateral meeting was held during the conference to explain and discuss in detail the pros and cons of the various methods used in the two countries.

On 10 March 2015, part of the project team participated in the expert workshop 'Options and solutions for promoting innovative heat and cooling supply concepts' in connection with the 'STRATEGO' project, and presented the current status of this project in a keynote speech on the constraints of and necessary conditions for district heating and cogeneration.

On 4 May 2015, part of the project team participated in the extended Advisory Board Meeting of the project 'Development of a district heating and cooling technology roadmap for Austria', which involved the presentation and discussion of the interim results. After the research focal points and accompanying measures determined had been presented, policy recommendations were drawn up during group discussions.

On 11 May 2015, the third and final stakeholder workshop in connection with this project was held on the premises of the Ministry for the Economy. The preliminary final results were presented to the 35 guests and discussed, and a workshop was held to draw up a list of constraints and barriers. When processing the results of the workshop, the general feedback was included where possible and appropriate, and the new results flowing out of that review were sent out to all relevant stakeholders from industry and the energy services sector, who were expressly asked for specific feedback on the individual points. It was possible to obtain further information by telephone and during bilateral meetings, and an attempt was made to find consensual solutions where divergences in opinion and assumptions lead to major variations in the results.