Long term (2050) projections of techno-economic performance of large-scale heating and cooling in the EU

External study performed by
ILF Consulting Engineers Austria GmbH, and
AIT Austrian Institute of Technology GmbH
for the Joint Research Centre

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Long term (2050) projections of techno-economic performance of large-scale heating and cooling in the EU

The following study provides data and projections for large-scale District Heating (DH) technologies including an outlook till 2050 and regional differences. The dataset for this study can be downloaded at http://data.europa.eu/89h/jrc-etri-techno-economics-larger-heating-cooling-technologies-2017

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List of abbreviations and definitions

AC	Alternating current
AIT	AIT Austrian Institute of Technology GmbH (Consultant)
ASUE	Arbeitsgemeinschaft für sparsamen und umweltfreundlichen Energieverbrauch e.V.
ATES	Aquifer thermal energy storage
BHKW	Blockheizkraftwerk
CAPEX	Capital expenditure
CHP	Combined heat and power
CHPP	Combined heat and power plant
CCGT	Combined cycle gas turbine
DH	District heating
EGS	Enhanced Geothermal System
EPC	Engineering, Procurement and Construction
ETC-CPC	Evacuated tube collector compound parabolic concentrator (solar thermal)
FOM	Fixed Operation and Maintenance expenses
FPC	Flat plate collector (solar thermal)
GFA	Gross floor area
GHI	Global horizontal irradiation
GIS	Geographical information system
GT	Gas turbine
HDPE	High-density polyethylene
HP	Heat pumps

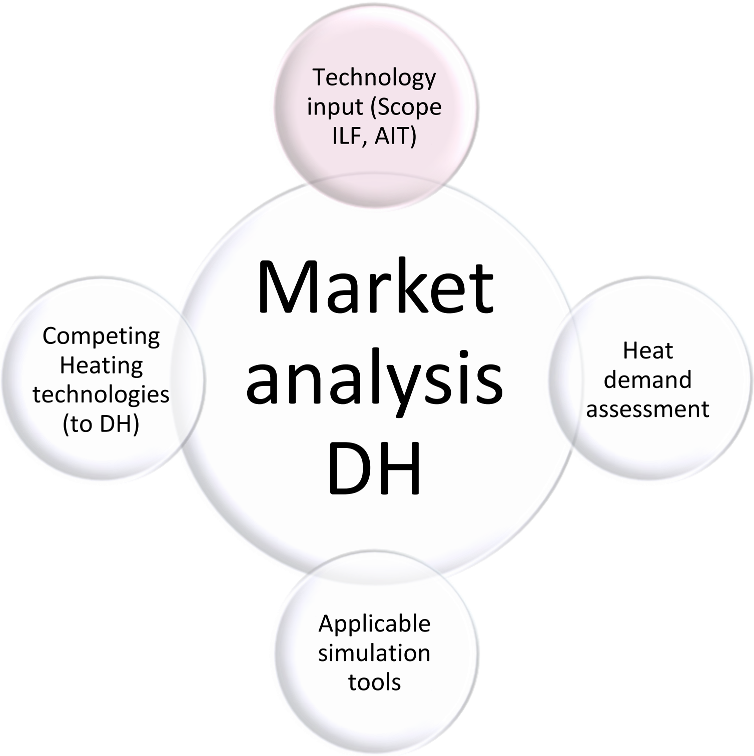
HRSG	Heat recovery steam generator
HSE	Health, Safety & Environment
I&C	Instrumentation and control
ICE	Internal combustion engines
IGC	Integrated gasification cycle
IGCC	Integrated gasification combined cycle
ILF	ILF Consulting Engineers Austria GmbH (Consultant)
ISO	International Organization for Standardization
JRC	Joint Research Center (Client)
O&M	Operation and maintenance
OEM	Original Equipment Manufacturer
OPEX	Operational expenditure
ORC	Organic Rankine cycle
PCM	Phase change material
PEMFC	Proton Exchange Membrane Fuel Cell
PTES	Pit thermal energy storage
rm	Route meter
SCR	Selective catalytic reduction
SOFC	Solid Oxide Fuel Cell
ST	Steam turbine
STG	Steam turbine generator
UTES	Underground thermal energy storage
VAT	Value-added tax
VOM	Variable Operation and Maintenance expenses

1 Introduction

The following study provides data and projections for large-scale District Heating (DH) technologies including an outlook till 2050 and regional differences. The study will also complement a similar study performed in 2016 for small-scale technologies applicable to residential and tertiary sector.

The study was designed and coordinated together with the modellers of the European Commission- DG Joint Research Centre (JRC) but is also addressed to anyone else interested in techno-economic data for heating and cooling technologies at the range of one to several hundered Megawatt (MW).

The provided information will be used in simulation tools in order to assess the possibilities of DH within the EU or specific countries.



2 Disclaimer

This report contains projections of techno-economic parameters of district heating and cooling technologies. All data in this report has been researched and compiled with utmost diligence of ILF/AIT experts.

Nevertheless there is no guarantee that the presented data captures all different kinds of district heating projects as well as errors and mistakes cannot be totally excluded.

Moreover projections contain considerable uncertainties since many factors will influence the development of these technologies both what concerns economic and technical performance.

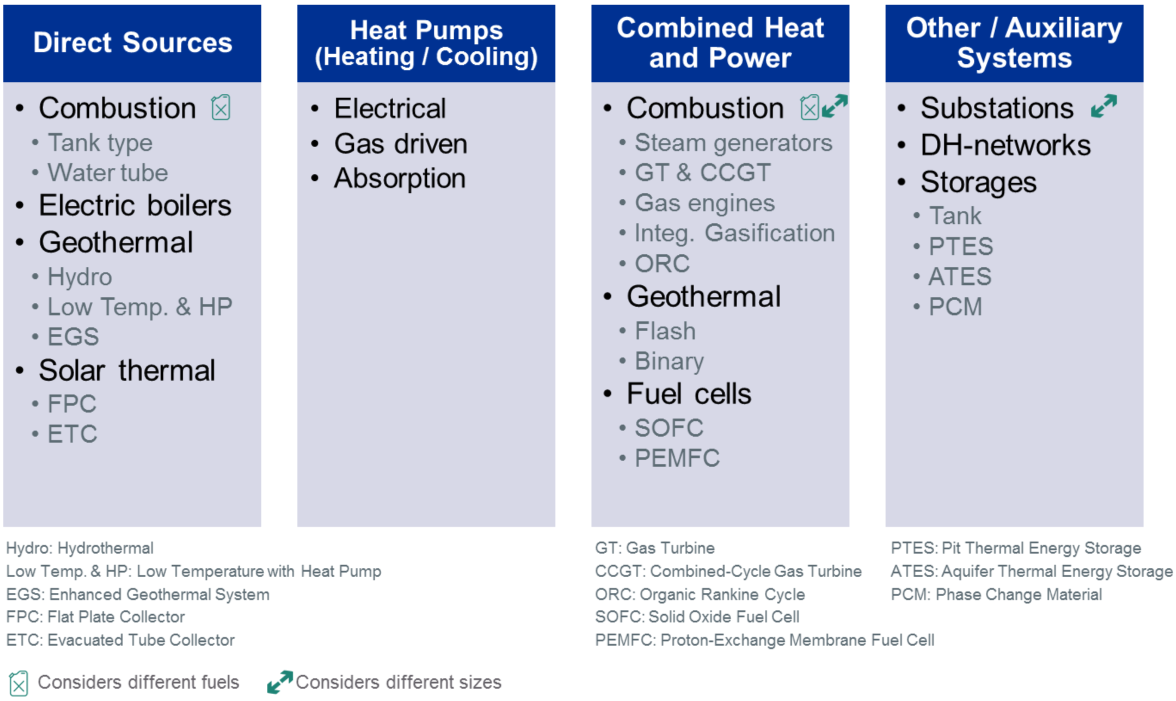
3 Methodology

The following chapter gives a comprehensive overview about the technologies, and parameters which are presented and changes that have been made in addition to the tender specifications – Part 2 - Technical specifications (Terms of Reference).

3.1 Technology overview

The following figure provides a summary of the different district heating technologies evaluated. All in all, 44 technology tables are elaborated which represent the most relevant technologies for district heating and cooling in the EU. When relevant, various fuel types are also considered for some technologies. Also own technology tables are provided if the capacity size has significant influence on the technology data (e.g. small- and large scale gas turbines).

Figure 1: Technology overview



Hydro: Hydrothermal
Low Temp. & HP: Low Temperature with Heat Pump
EGS: Enhanced Geothermal System
FPC: Flat Plate Collector
ETC: Evacuated Tube Collector

GT: Gas Turbine
CCGT: Combined-Cycle Gas Turbine
ORC: Organic Rankine Cycle
SOFC: Solid Oxide Fuel Cell
PEMFC: Proton-Exchange Membrane Fuel Cell

PTES: Pit Thermal Energy Storage
ATES: Aquifer Thermal Energy Storage
PCM: Phase Change Material

3.2 Data sources and approach

General data

For data gathering following information sources were used/ combined:

- Literature
    - Public and own studies
    - Scientific- and conference papers
    - Databases
- Project information
    - Realised and planned plants
    - Fact sheets and best practice examples

  - Own projects
  - Estimative offers
  - Reference projects
- Measurements
  - Monitoring/operational data
  - Laboratory/test bench
- Reference projects (interviews, literature, etc.)
- Internal and external expert inputs
  - Opinions, estimations and assessments
  - Information from manufacturers and planners (interviews)
- Simulations/Calculations
  - Commercial tools/ SW
  - In-house/own developed tools

Additional to these data sources, inhouse knowledge of ILF/AIT was used and internal experts continuously consultated for contribution and reviewing the gathered technology data.

Long term projection

Based on the past and current economic and technical performance future projections were done. To maximize the accuracy of the projections, three steps were used for all technologies:

- Extrapolation of past and current data
- Expert opinion regarding market trends, material development, political regulations
- Literature study considering latest scientific findings, trends and possible disruptive developments

3.3 Parameters

3.3.1 General format - Overview

Within the following report key parameters of district heating technologies are provided. Each chapter includes one technology first giving a general overview, a main data table with different kind of information being separated into the following major categories which are:

- Energy/technical data
- Environmental data
- Financial data
- Technology specific data.

3.3.2 Energy/technical data

Heat/Cold generation capacity

The range indicates the typical capacities in which one unit of the technology is available/ used for the considered application.

Total efficiency, annual average

The efficiencies are calculated based on the net energy content of the fuel used and the net amount of heat/cold/electricity produced, in percent, at ambient conditions representative of relevant climatic conditions/zones. The transformation on different locations within Europe will be illustrated in chapter 3.4.1. Efficiencies reflect annual average efficiencies as experienced by the operator, assuming correct installation and operation. When technologies are having a large variation over the year we will give monthly efficiency indicators.

Technical lifetime

The average lifetime of the main equipment is indicated.

Type of DH output

Some district heating technologies are highly dependent on net supply and deliverable temperature which affects heat generation and the efficiency. If for example a geothermal source with a temperature output of 105 °C can be accessed, but an existing district heating network needs to be operated with a temperature output of 135 °C and the returning water has a tempetature of 80 °C (135/80 °C), the geothermal source can only be cooled down by 15 to 20 K and the source cannot bring the water up to the required temperature of 135 °C. If the network is however been operated at low temperatures of 70/50 °C the use of more than 50 K seems to be possible which leads to a 2 to 3 times higher thermal output.

For a qualitative consideration of this effect, a proportional factor for the following temperature classes of the district heating output will be shown:

- Steam supply (185/100 °C)
- Hot water (135/80 °C)
- Warm water (105/60 °C)
- Low temperature (70/50 °C)

With ++/-- = ± 5-10% change in efficiency/heat generation output
+/- = ± 3-5% change in efficiency/heat generation output
(+)/(-) = ± 0-3% change in efficiency/heat generation output
o/(o) = no relevant change / reference value

If the given temperature levels does not fit to a technology, the adapted temperature is listed separated in the technology table (see thermal heat storages “PTES” and “ATES”).

Following the heat generation or efficiency can change at some technologies based on different output temperatures. At the other hand, total investment costs, fixed operation costs or electric consumption remain unchanged. As a result also specific parameters have to be adapted like CAPEX or fixed OPEX.

To take this into account these parameters also have to be adapted with the following equation:

$$CAPEX_{Steam} = \frac{CAPEX_{RefOutput}}{(1 + proportional\ factor\ DH\ type)}$$

If CAPEX or OPEX will be presented €/MWel or €/MWh as shown within the CHP-technology there will be no need for adaption. In this case the heat output has to be adapted.

3.3.3 Environmental data

Direct emissions are indicated as g/GJ_{th} thermal output except CO2 which is presented as g/MJ_{th}. If a technology is electricity driven the main emissions are related to the emission factor for electricity which are not provided in this study

3.3.4 Financial data

The given data refers to the thermal power output except for CHP plants which refers to the electrical output. The reference year for all technologies is harmonized to 2015. The data exclude VAT and any other tax.

Quality of Capital Expenditure (CAPEX) estimation

It should be understood that uncertainties are inherent in long term projections since numerous factors will influence the evolution of the costs, e. g. learning rates, energy policy support decisions, global and national economic growth, and competition with other technologies. Therefore, the qualities of the given CAPEX figures are indicated with the three categories:

- high (indicates high amount of considered/available data and/or low deviations)
- medium (indicates medium amount of considered/available data and/or deviations)
- low (indicates few amount of considered/available data and/or high deviations)

Learning rate

The learning rate[1] is an empirical concept which quantifies the effects of learning-by-doing on the capital cost of technologies. The concept assumes that capital costs of technologies reduce at a constant rate with each doubling of the installed cumulative capacity (plotted as a power-law function).

Learning rates are normally built by evaluation of historical cost developments. On the one hand this work deals with long term projections, why statements about learning rates in the future, especially for “new” technologies with less historical data, could not be done with a high scientific valuable approach. On the other hand, given learning rates for far developed technologies have also a spread through different studies[2].

That is why, learning rates could not be provided for all technologies and deviations and uncertainties has to be accepted. Some figures are based on indications/estimations by the authors and if known a qualitive explanation is given concerning cost reduction potentials.

Note: Mature technologies normally have lower learning rates.

3.3.4.1 CAPEX

Nominal investment

CAPEX is the cost of delivery of a plant as if no interest was incurred during construction. That means cost of financing is excluded (i.e. this can be considered as "overnight CAPEX").

The nominal investment is further divided into “**equipment**” and “**installation**”. The equipment contains effort which are independent of regional differences (e.g. central production in one factory). On the other hand, the installation includes the part which is

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[1] concept was developed in the 1970s by the Boston Consulting Group

[2] Example given:
Learning rates for energy technologies; L. Schrattenholzer and A. McDonald, 2000
A review of learning rates for electricity supply technologies; E.S. Rubin et al., 2015
A review of experience curve analyses for energy demand technologies; M. Weiss et al., 2010

dependent on regional differences (e.g. changing on-site effort through labour cost differences and other conditions).

Breakdown

A breakdown structure shows up what is covered in the nominal investment costs.

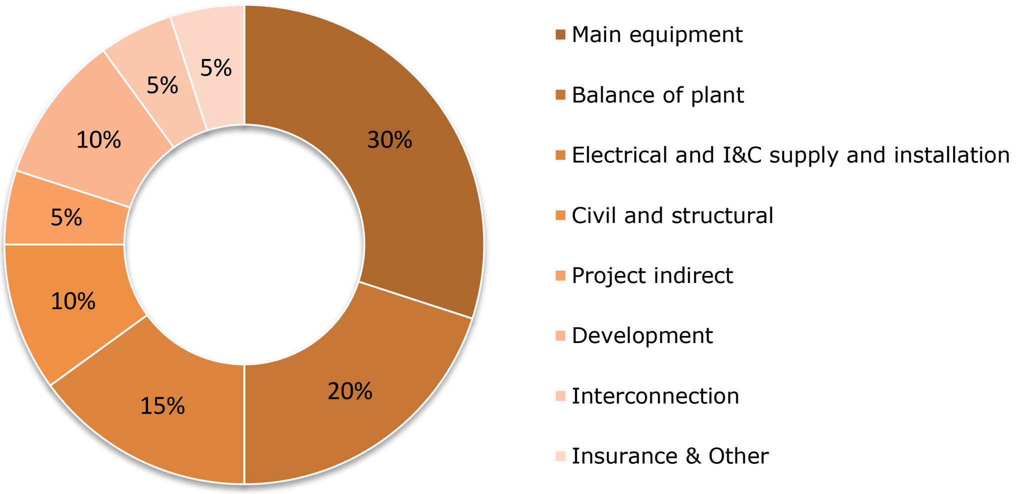
If land acquisition cost will be shown we want to remark that it is highly depending on the local situation, which is quickly changing.

Also interconnection costs are highly depending on individual projects and already installed infrastructure. If this will lead to lower estimation accuracy we will neglect these costs and will give a corresponding explanation.

The CAPEX breakdown structure as seen in Figure 2 further points out the allocation between installation and equipment costs in order to improve the accuracy of projected costs within Europe and includes the categories:

☒ Main equipment
☒ Balance of plant
☐ Electrical and I&C supply and installation
☐ Civil and structural
☐ Project indirect
☐ Development
☐ Interconnection
☐ Insurance & Other

Figure 2: Illustration of CAPEX breakdown



Main equipment

Supply and installation costs of core-components like for instance boilers, cooling towers, steam turbine generators, condensers, photovoltaic modules, combustion turbines.

Balance of plant

Supply and installation costs not included in the primary system, e.g. compressors, pumps, piping.

Electrical and I&C supply and installation

Costs included here are for instance electrical transformers, switchgear, switchyards, instrumentation.

Civil and structural

Costs for site preparation excluding the costs of infrastructure connections, i.e. electricity, fuel and water connections. These are for example construction of buildings and roads on the site, drainage, construction of buildings on the site.

Project indirect

These costs are not directly accountable to a cost object. They can include engineering, construction management, security costs, contractor overhead costs, maintenance, and construction contingency.

Development

Costs that the utility will have to pay in addition to the engineering, procurement and construction, e.g. preliminary feasibility and engineering studies, permits, legal fees, land acquisition, taxes, licensing.

Interconnection

Costs for infrastructure connections, i.e. electricity, fuel and water.

Insurance & Other

Insurance and other costs which are not included in the listed categories.

3.3.4.2 OPEX

OPerating EXpenditure (OPEX) results from the ongoing costs to run a plant. The operational costs are divided into the two categories:

Fixed operation and maintenance costs (FOM)

Fixed operational costs are indicated in [k€/MW/year] and/or [% of CAPEX/year] and include periodic O&M service and, where relevant, costs related to administration, operational staff and insurance.

Fixed operational costs do not vary significantly with a technology's energy generation/consumption. They are independent from how the plant is operated.

Fixed operational costs exclude any costs of refurbishment needed to extend lifetime beyond technical lifetime.

Variable operation and maintenance costs (VOM)

Variable operational costs are indicated in [€/MWh].

Variable Operation and Maintenance expenses are production-related costs which vary with energy generation and consumption, respectively.

They exclude personnel, fuel and CO2 emission costs.

3.3.5 Technology specific data

Including any issues faced when determining the value of the performance indicators, in order to help data users to understand and interpret the data and get detailed information about the technology.

CAPEX scaling factor

In this section, when known and relevant, a scaling factor/formula for the CAPEX costs depending on the unit size or different typical sizes is presented. The factor/formula is valid for the given reference scale if no further description/restriction is made.

3.4 Regional differences

The study provides information to ensure that different conditions within Europe will be considered in order to improve the accuracy of parameters. For each parameter and technology named below, the effect for different specific locations and identify correction/proportional factors is discussed.

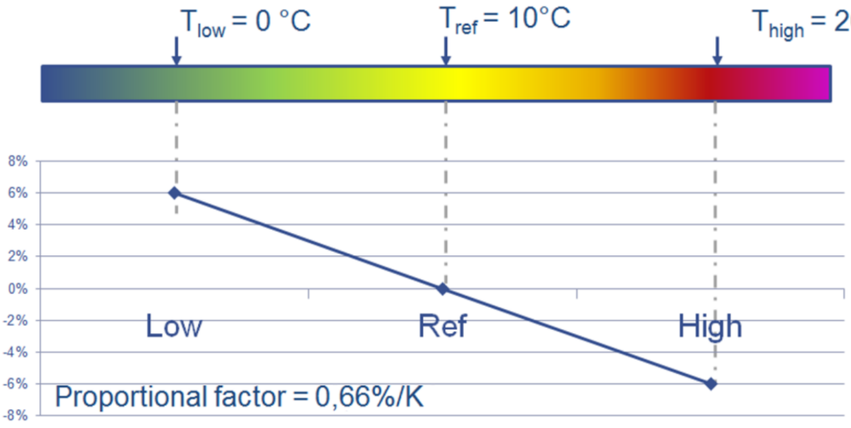
Therefore, relevant data were analysed and appropriate dependencies calculated. Based on these figures and graphics the dependencies in different locations can be evaluated and this correction factor can be taken into account by the user.

Following parameters/ projections were analysed:

- Average air temperature
- Average global horizontal irradiation (GHI)
- Geothermal energy
- Cost transformation

As an example the output of a gas turbine (GT) according to mid-outside temperature is shown below.

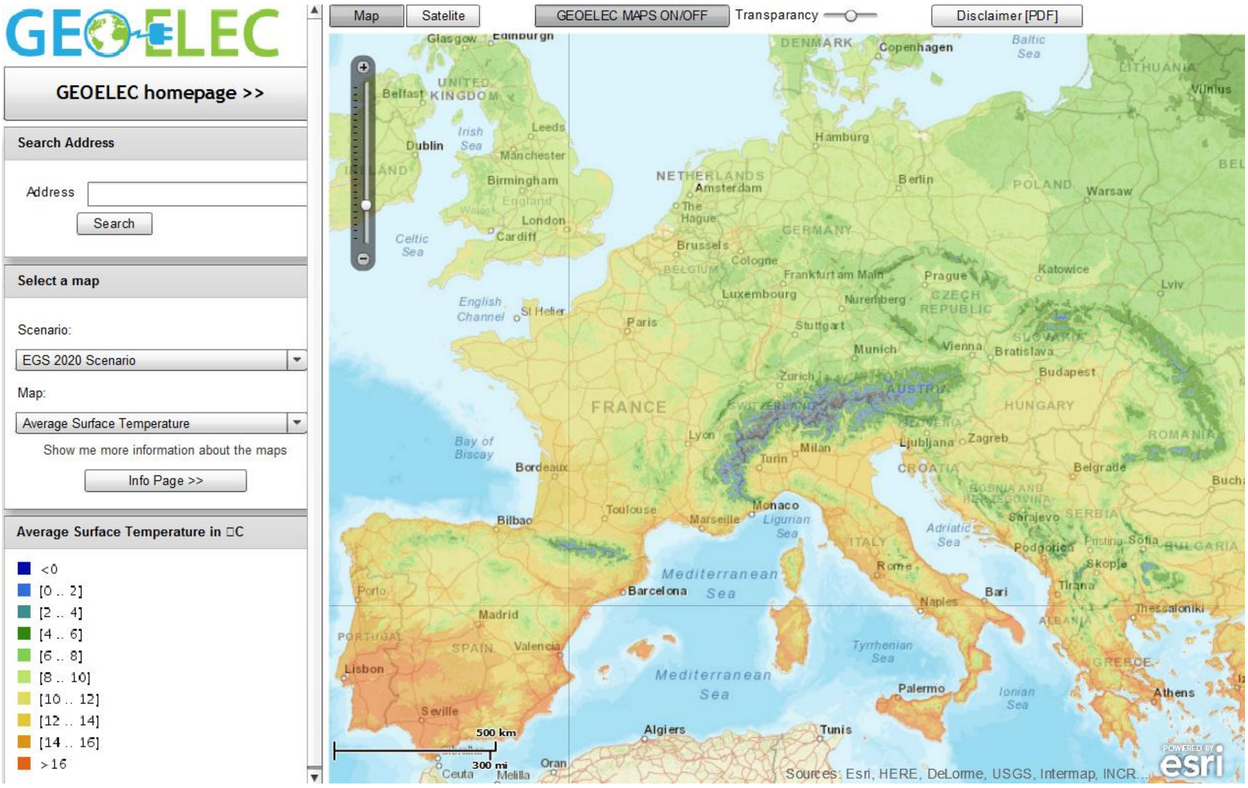
Figure 3: Example calculation of a proportional factor regarding GT electrical output in accordance to average outside temperatures



3.4.1 Temperatures

Ambient air temperatures are relevant for gas turbines, combustion technologies and in lower relevance also for DH and storage losses and solar thermal efficiency.

Figure 4: Average surface temperatures



Scenario: EGS 2020 Scenario

Map: Average Surface Temperature

Average Surface Temperature in □C

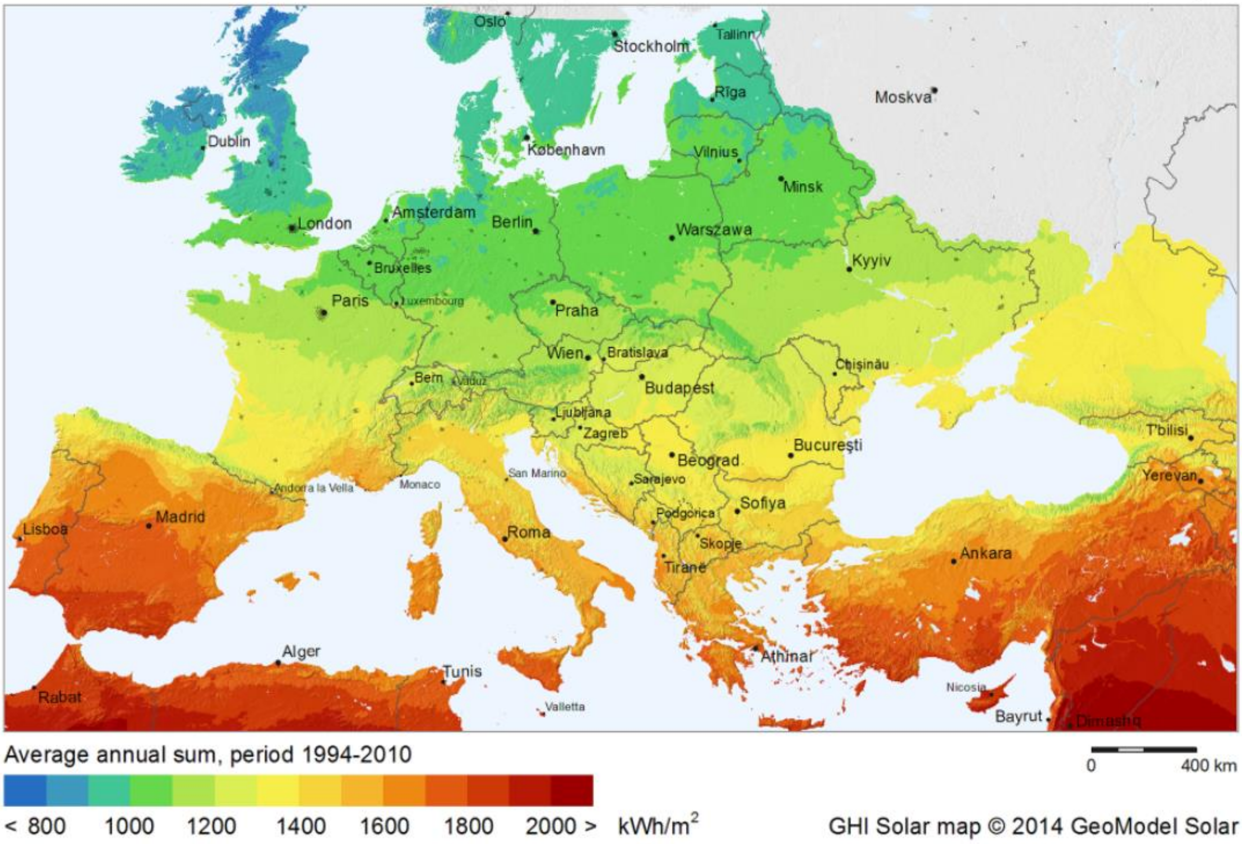
- ■ <0
- ■ [0 .. 2]
- ■ [2 .. 4]
- ■ [4 .. 6]
- ■ [6 .. 8]
- ■ [8 .. 10]
- ■ [10 .. 12]
- ■ [12 .. 14]
- ■ [14 .. 16]
- ■ >16

Source: http://www.thermogis.nl/geoelec/ThermoGIS_GEOELEC.html

3.4.2 Average global horizontal irradiation GHI

The average global horizontal irradiation (GHI) is taken into account for solar thermal systems.

Figure 5: Global Horizontal Irradiation across Europe



Source: http://solargis.com/assets/graphic/free-map/GHI/Solargis-Europe-GHI-solar-resource-map-en.png

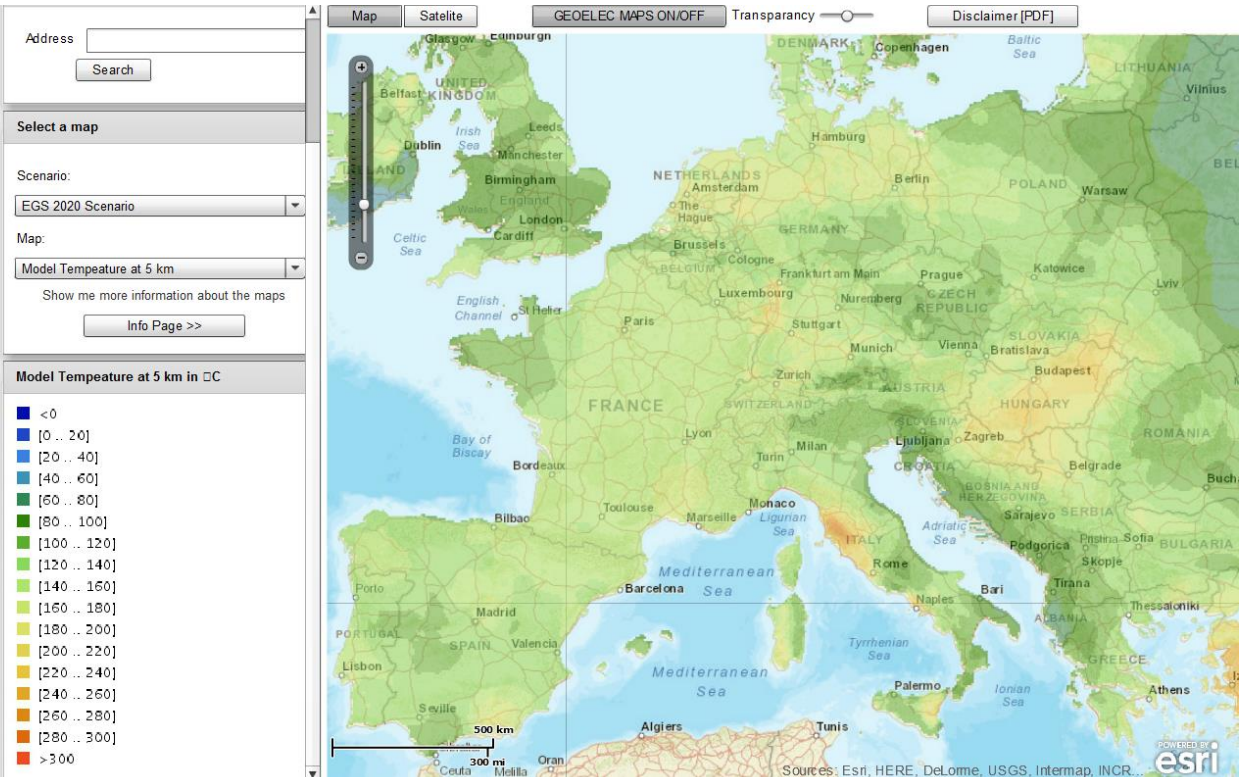
3.4.3 Geothermal potential

The output of a geothermal heating plant highly correlates to the estimated layer temperature.

Moreover investment costs are depending on the depth of the drillings and which type of extraction technology is used (EGS or direct use at aquifer layers).

For a better user convenience information published on the [GEOLEC GIS system]() is proposed.

Figure 6: Geothermal temperature at 5 km depth


Scenario: EGS 2020 Scenario

Map: Model Tempeature at 5 km

Source: http://www.thermogis.nl/geoelec/ThermoGIS_GEOELEC.html

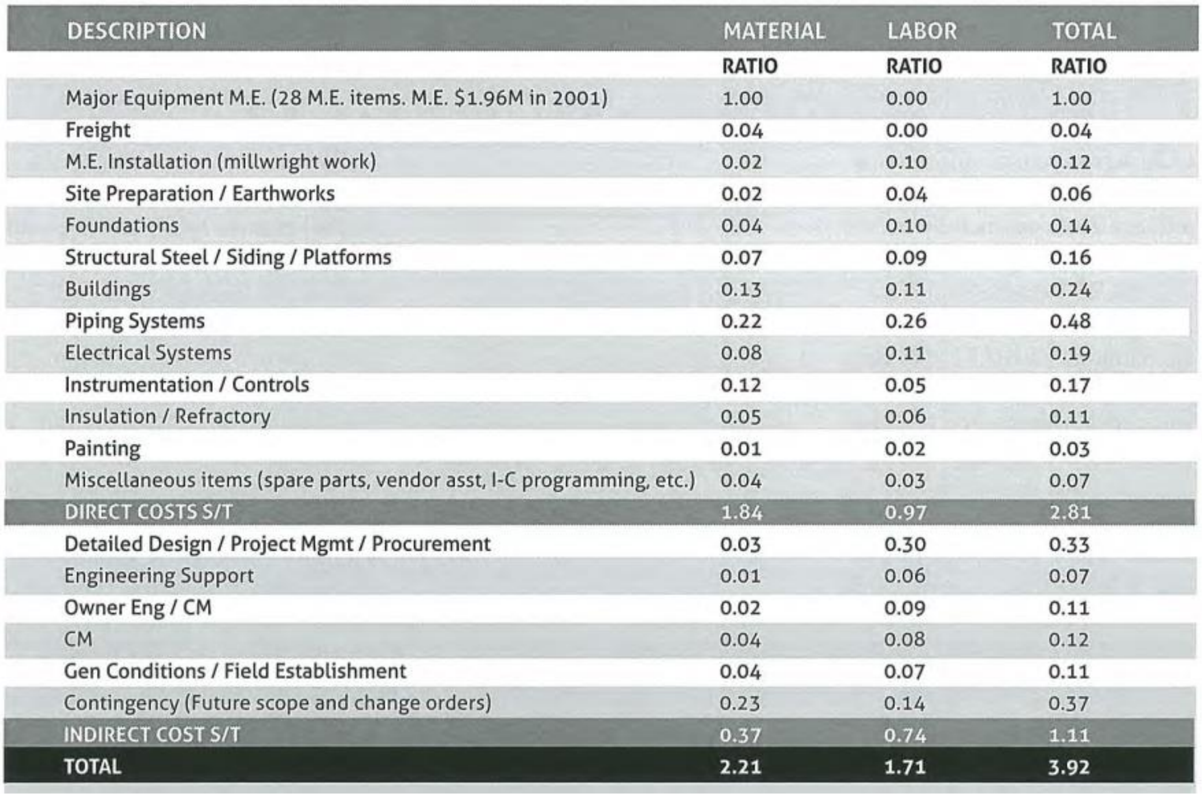
3.4.4 Cost transformation

In order to consider regional differences within Europe in terms of capital expenditure (CAPEX) the nominal investment shown below is split into the two groups: main equipment and installation (which includes also labour costs).

With regards to main equipments it is assumed, that within Europe there are no significant differences because core elements like gas- or steam turbine modules, large-scale heat pumps but also electrical subsystems like high voltage transformers are only produced by a handful of international technology companies with different supply chains and several locations for the final assembly. This information was gathered from multiple manufacturers.

At the over hand, different goods and services for building up a district heating/cooling infrastructure can or have to be provided with local partners. Some examples for such services: civil work and site management and authority approval including Health, Safety & Environment (HSE) studies but also some auxiliary equipment like controls and wiring or insulation. The following figure gives a comprehensive overview for different groups of installation:

Figure 7: Typical material and labour ratio for direct and indirect costs

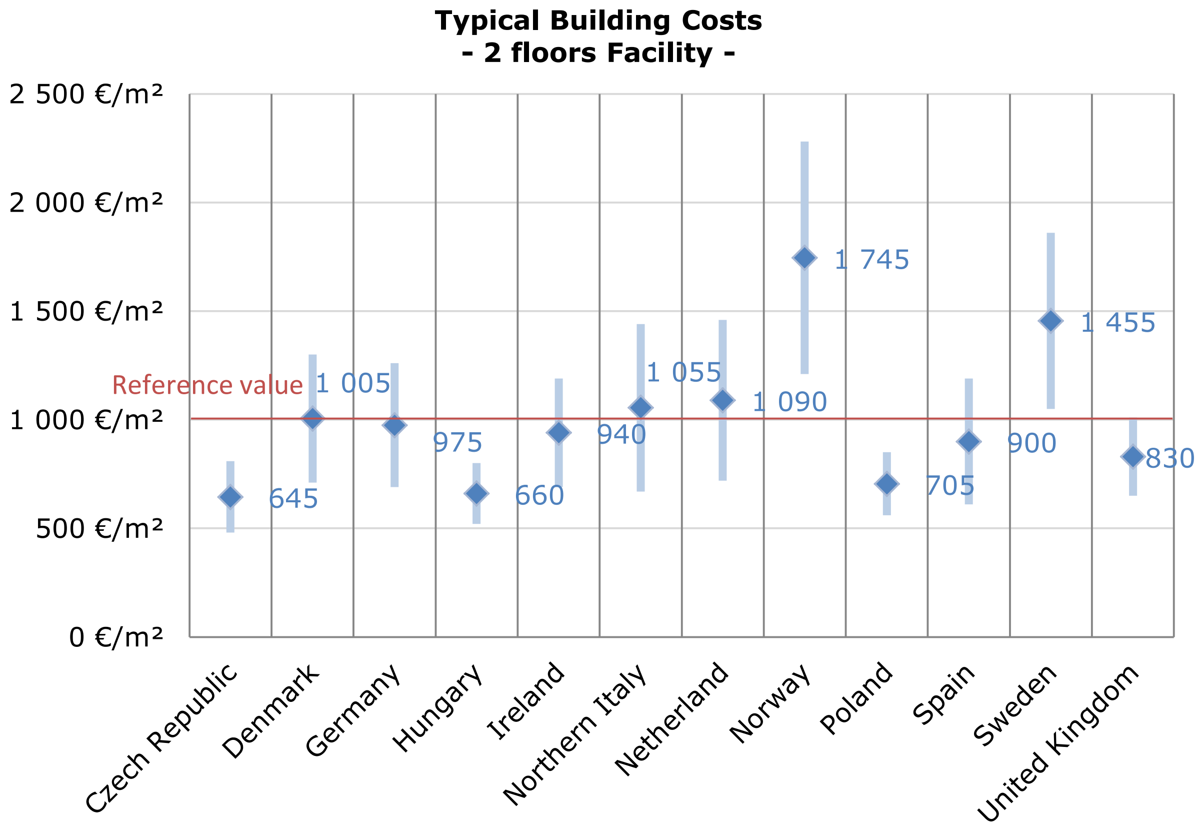


DESCRIPTION	MATERIAL RATIO	LABOR RATIO	TOTAL RATIO
Major Equipment M.E. (28 M.E. items. M.E. $1.96M in 2001)	1.00	0.00	1.00
Freight	0.04	0.00	0.04
M.E. Installation (millwright work)	0.02	0.10	0.12
Site Preparation / Earthworks	0.02	0.04	0.06
Foundations	0.04	0.10	0.14
Structural Steel / Siding / Platforms	0.07	0.09	0.16
Buildings	0.13	0.11	0.24
Piping Systems	0.22	0.26	0.48
Electrical Systems	0.08	0.11	0.19
Instrumentation / Controls	0.12	0.05	0.17
Insulation / Refractory	0.05	0.06	0.11
Painting	0.01	0.02	0.03
Miscellaneous items (spare parts, vendor asst, I-C programming, etc.)	0.04	0.03	0.07
DIRECT COSTS S/T	1.84	0.97	2.81
Detailed Design / Project Mgmt / Procurement	0.03	0.30	0.33
Engineering Support	0.01	0.06	0.07
Owner Eng / CM	0.02	0.09	0.11
CM	0.04	0.08	0.12
Gen Conditions / Field Establishment	0.04	0.07	0.11
Contingency (Future scope and change orders)	0.23	0.14	0.37
INDIRECT COST S/T	0.37	0.74	1.11
TOTAL	2.21	1.71	3.92

Source: 2016 Global Construction Costs Yearbook, Compass International Consultants Inc.

In order to consider differences within Europe, specific country conditions have been evaluated like hourly income for workers, construction material benchmark for facility buildings and other figures. These are shown below:

Figure 8: Typical Building costs within Europe



Source: 2016 Global Construction Costs Yearbook, Compass International Consultants Inc.

Most of the technologies in this report are based on the reference value of Central Europe (Germany/Austria/Switzerland)[3] with an indicator value of 1.000. But it has to be noted, that there will be also regional differences within one country (i.e. for Germany in between 690 and 1290).

$$CAPEX_{New\ Country} = CAPEX_{Equipment} + CAPEX_{Installation\ Ref CentralEurope} * \frac{Costindex\ New\ Country}{Costindex\ Ref Country}$$

To give an example the CAPEX of tank type boiler with in total 0.11 M€/MW shall be transferred from the reference value (Central Europe) to the country of Norway. To do so, the installation cost of 0.04 M€/MW can be changed by the factor of 1 745 divided by the reference value of 1 000. The equipment cost of 0.07 M€/MW will stay unchanged.

$$CAPEX_{Norway} = 0.07 \frac{M€}{MW} + 0.04 \frac{M€}{MW} * \frac{1\,745}{1\,000} = 0.1398 \frac{M€}{MW}$$

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[3] If projects from other countries are taken into account, they are indicated separately.

3.4.5 Summary

Based on both calculations/simulations and experience/measurements the table below was developed under consideration of the above mentioned parameters and their dependencies to some technologies.

Table 1: Overview of regional differences in parameters, technologies and regions

Parameter	Technology	Reference region	Reference temperature	Proportional factor	Dependency
Temperatures	Gas turbines	Central	9°C	0.6 %/K	Heat generation capacity
	Combustion	Central	9°C	< 0.1 %/K	Total degree of utilization
	District Heating Network	Central	9°C	1.5 %/K	Net loss
	Tank Storages	Central	9°C	< 0.1 %/K	Total efficiency, nominal load
	Remaining Storages	Central		2.1 %/K	Annual losses
	Solar thermal	Central	9°C	2.4 %/K	Annual collector yield
	Heat pumps	Central	9°C	description in chapter 5.1	
Average GHI	Solar thermal	Central	9°C	0.05 %/GHI	Annual collector yield
Geothermal	Geothermal	Central	9°C	description in chapter 4.3	
Costs	All	Central	-	description in chapter 3.4.4	

4 Direct Sources

4.1 Combustion - Hot water boilers

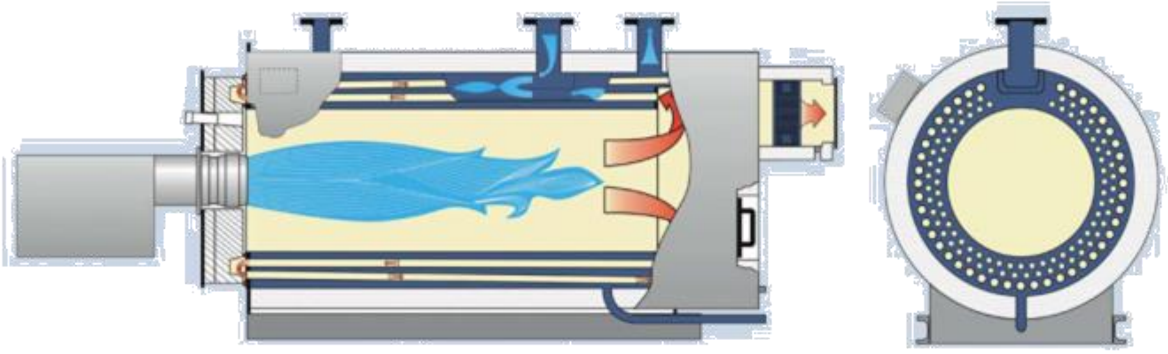
Such units are used to combust different materials like fossil fuels, biomass or even waste. The related heat enthalpy is then used for heating up water or to produce steam.

This type of technology has been developed for decades and is nowadays often used within peak-load periods and as a backup unit.

4.1.1 Tank type boilers (1 to 20 MW)

Tank type boilers are factory prepared by several suppliers and highly available within the range of 1 to 20 MW. The integrated burner is able to use fluid and/or gaseous combustibles within the furnace section.

Figure 9: Section of a one furnace tank type boiler



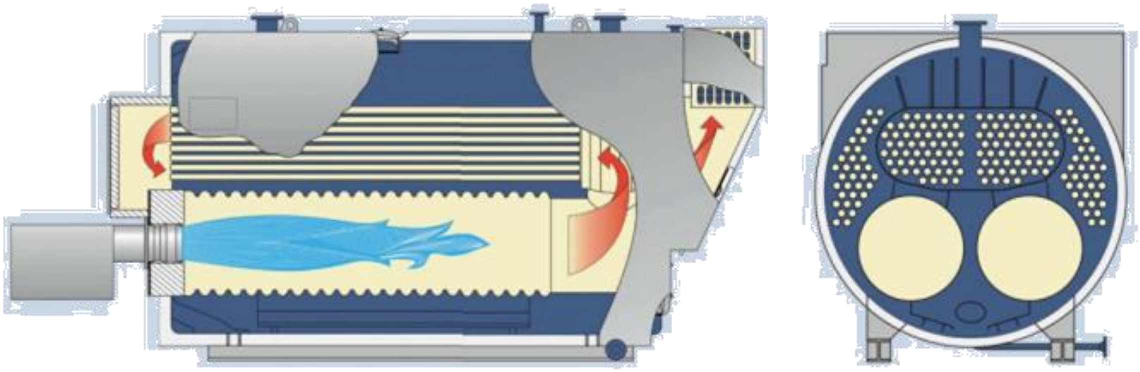
Source: https://www.bosch-industrial.co.uk/files/201309111326480.BR_HotWaterBoilers_en.pdf

These boilers are separated into a shell section for the hot flue gas and the tube section in which the water used within the district heating network is warmed up or vaporized into steam. The heat of the flame is transmitted via multiple fire tubes.

After leaving the boiler, the exhaust gas can be cooled down or even condensed further within an economizer. The overall efficiency of this unit is highly depending on the temperature level of the incoming water.

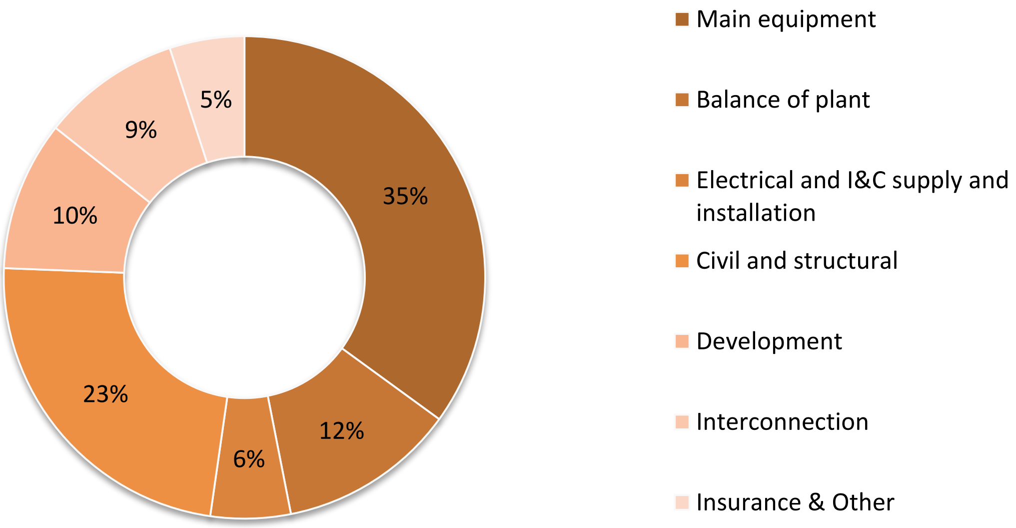
To increase the flexibility and maximize the thermal output of a tank type boiler up to 30 MW, it can be divided into two furnace sections with separate burners.

Figure 10: Section of a two furnace tank type boiler



Source: https://www.bosch-industrial.co.uk/files/201309111326480.BR_HotWaterBoilers_en.pdf

Figure 11: CAPEX breakdown of a heating plant only based on hot water boilers (tank type)



The electricity consumption is mainly caused by the boiler water pump (and the fresh air fan which overcomes internal pressure losses.

Table 2: Overview of hot water boilers – tank type

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Heat generation capacity	MW_{th}	1-30											A	
Total efficiency, nominal load	%	97	97	98	98	98		95	98	95	98		B	1,2
Total efficiency, annual average	%	93	93	94	94	94		85	95	88	95		C	1,2
Electricity consumption	%/MWth	0.5	0.5	0.5	0.5	0.4		0.4	0.8	0.3	0.7		L,F	1
Technical lifetime	years	25	25	25	25	25		25	>25	25	>25		K	
Steam supply		-	-	-	-	-		--	-	--	-		D	
Hot water (up to 140°)		(-)	(-)	(-)	(-)	(-)		(-)	o	(-)	o		D	
Warm water (up to 105°C)		(o)	(o)	(o)	(o)	(o)		(o)	o	(o)	o		D	
Low temperature (up to 70°C)		+	+	+	+	+		+	++	+	++		D	
B. Environmental data														
CO2	g/MJth	65	65	65	65	65		60	80	60	75		H	
SO2	g/GJth	1.0	1.0	1.0	1.0	1.0							H	
NOX	g/GJth	20	20	15	15	15		5	60	5	40		G	1, 2,
CH4	g/GJth	1.0	1.0	1.0	1.0	1.0		0.1	5	0.1	5			1, 2, 3
N2O	g/GJth	0.2	0.2	0.15	0.15	0.15		0.15	0.40	0.1	0.3			2,3
Particles	g/GJth	0.05	0.05	0.05	0.05	0.05		NA	NA	NA	NA		H	1
C. Financial data														
Quality of CAPEX estimation		high												
Nominal investment	M€/MW	0.11	0.11	0.11	0.11	0.11		0.08	0.3	0.05	0.25		J	2,4
- of which equipment	M€/MW	0.07	0.07	0.07	0.07	0.07		0.05	0.2	0.03	0.2		J	2,4
- of which installation	M€/MW	0.04	0.04	0.04	0.04	0.04		0.03	0.1	0.01	0.1		J	2,4
Fixed O&M	k€/MW/a	3	3	3	2	2		1	5	1	5		F	
Variable O&M excl. electricity costs	€/MWh	0.5	0.5	0.5	0.5	0.5		0.2	1.0	0.3	0.8		F	
X. Technology specific data														
Cost function (estimation)	M€/MW_{th}	Invest(x)=$0.17x^{-0.15}$											M	

References:

1 Burner and boiler manufacturer information, 2016
2 Technology Data for Energy Plants, Danish Energy Agency, 2016
3 Non-CO2 greenhouse gas emissions from boilers and industrial processes, VTT 2005
4 Project information, 2016

Notes:

A For the limit for one furnace boilers will be ~14 MW, for gas fired boiler ~17 MW. Range can be increased with two furnace system.
B Includes a condensing economizer, without economizer the efficiency will be up to some 90-92 %, LHV reference.
C Includes a condensing economizer, without economizer the efficiency will be up to some 88-90 %, LHV reference.
D Efficiency depends on incoming water temperature. Assumptions been made: steam: 95 °C (-2% eff.), hot water: 75 °C (-1% eff.), warm water: 60 °C (Ref.), low temp.: 40 °C (+5% eff.).
F ILF/AIT calculations/estimations.
G Ultra-Low NOx burners can reach a level of 5 g/GJ, the use of oil instead of gas will increase NOx-emissions.
H Fuel dependent, not technology dependent.
J The average numbers are for an 18 MW heating plant with one gas boiler, included economizer (+1 MW) costs and additional piping ~90 T€/MW.
K Technical lifetime of the tank often exceeds 25 years, burner needs to be retrofitted after 15-25 years (depending on emission regulations).
L Mainly caused by the feed water pump (~1-2 kW/MWth) and fresh air fan (~3-5 kW/MWth).
M x…Heat generation capacity [1 MW$_{th}$ … 30 MW$_{th}$].

4.1.2 Water tube boilers (above 20 MW)

The basic definition of a water tube boiler is that water is heated inside tubes by hot gases surrounding these tubes. Water tube boilers are also used for higher thermal powers above 20MW$_{th}$ and since there are many different types, these boilers can be designed for almost any fuel and burner system, respectively. Main process parameters for the water can go up to 30 bar and 250 °C, individually designed. For the CAPEX breakdown indication see chapter above.

4.1.2.1 Natural gas fired hot water tube boilers

Table 3: Overview of natural gas fired hot water tube boilers

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**		A	1, 2, 4
Heat generation capacity	MW_{th}	20 - 250												
Total degree of utilization, nominal load	%	95	95	95	95	95		90	96	92	97			
Total degree of utilization, annual average	%	87	87	87	87	87							B, C	
Electricity consumption	%	0.5	0.5	0.4	0.4	0.4		0.3	0.7	0.3	0.7		D	
Technical lifetime	years	30	30	35	35	40		30	50	30	50			
Steam supply		-	-	-	-	-		--	-	--	-			
Hot water		o	o	o	o	o		(-)	o	(-)	o			
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	o	(o)	o			
Low temperature		+	+	+	+	+		+	++	+	++			
B. Environmental data														5, 6, 7
CO2	g/MJ_{th}	60	60	60	60	60		30	70	30	70			
SO2	g/GJ_{th}	<	<	<	<	<								
NOX	g/GJ_{th}	20	20	18	18	15		15	50	10	40			
CH4	g/GJ_{th}	<	<	<	<	<								
N2O	g/GJ_{th}	<	<	<	<	<								
Particles	g/GJ_{th}	<	<	<	<	<								
C. Financial data														1, 3, 8
Quality of estimation		medium												
Nominal investment	$M€/MW_{th}$	0.1	0.1	0.1	0.1	0.1		0.05	0.12	0.05	0.12			
- of which equipment	$M€/MW_{th}$	0.06	0.06	0.06	0.06	0.06		0.03	0.07	0.03	0.07			
- of which installation	$M€/MW_{th}$	0.04	0.04	0.04	0.04	0.04		0.02	0.05	0.02	0.05			
Fixed O&M	$k€/MW_{th}/a$	2	2	1.9	1.9	1.8		1	4	1	5			
Variable O&M excl. electricity costs	$€/MWh_{th}$	0.2	0.2	0.2	0.2	0.2		0.1	0.5	0.1	0.5			
X. Technology specific data														
Cost function (estimation)	$M€/MW_{th}$	$Invest(x)=0.27x^{-0.20}$											E	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Workshop BOSCH: Fachseminar Auslegung und Planung von Thermischen Großanlagen
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 „Projektmanagement im Energiebereich‟, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013

Notes:

A Natural gas (LHV appr. 40 MJ/kg) fired hot water tube boiler (3% O_2 flue gas)
B based on planned availability of 8 000 h/a (DH+GEN)
C uncertainty depending on (unplanned) maintenance
D $MW_{el,aux.pwr}/MW_{th}$
E x…Heat generation capacity [20 MW_{th} … 250 MW_{th}]

4.1.2.2 Biogas fired hot water tube boilers

Table 4: Overview of biogas fired hot water tube boilers

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**		A	1, 2, 4, 9, 10
Heat generation capacity	MW$_{th}$	20 - 250												
Total degree of utilization, nominal load	%	85	85	85	85	85		83	93	83	93			
Total degree of utilization, annual average	%	78	78	78	78	78							B, C	
Electricity consumption	%	0.5	0.5	0.4	0.4	0.4		0.3	0.7	0.3	0.7		D	
Technical lifetime	years	25	25	30	30	30		20	35	20	35			
Steam supply		-	-	-	-	-		--	-	--	-			
Hot water		o	o	o	o	o		(-)	o	(-)	o			
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	o	(o)	o			
Low temperature		+	+	+	+	+		+	++	+	++			
B. Environmental data														5, 6, 7, 10
CO2	g/MJ$_{th}$	130	130	130	130	130		80	150	80	150			
SO2	g/GJ$_{th}$	<	<	<	<	<								
NOX	g/GJ$_{th}$	23	23	22	22	20		15	50	10	30			
CH4	g/GJ$_{th}$	<	<	<	<	<								
N2O	g/GJ$_{th}$	<	<	<	<	<								
Particles	g/GJ$_{th}$	<	<	<	<	<								
C. Financial data														1, 3, 8, 9, 11
Quality of estimation		medium												
Nominal investment	M€/MW$_{th}$	0.105	0.105	0.105	0.105	0.105		0.05	0.12	0.05	0.12			
- of which equipment	M€/MW$_{th}$	0.065	0.065	0.065	0.065	0.065		0.03	0.03	0.03	0.03			
- of which installation	M€/MW$_{th}$	0.04	0.04	0.04	0.04	0.04		0.02	0.02	0.02	0.02			
Fixed O&M	k€/MW$_{th}$/a	2.2	2.2	2.1	2.1	2		1	5	1	5			
Variable O&M excl. electricity costs	€/MWh$_{th}$	0.2	0.2	0.2	0.2	0.2		0.1	0.5	0.1	0.5			
X. Technology specific data														
Cost function (estimation)	M€/MW$_{th}$	Invest(x)=0.28x$^{-0.20}$											E	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation ; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Workshop BOSCH: Fachseminar Auslegung und Planung von Thermischen Großanlagen
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 „Projektmanagement im Energiebereich", Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
9 Wien Energie: Biomasse Kraftwerk Simmering
10 Rechnungshofbericht Wien Energie Bundesforste Biomasse Kraftwerk
11 Wirtschaftlich effiziente Biomasse-Heizkraftwerke, Rolf Michler

Notes:

A Biogas (LHV appr. 6.2 MJ/kg) fired hot water tube boiler (3% O_2 flue gas)
B based on planned availability of 8000 h/a (DH+GEN)
C uncertainty depending on (unplanned) maintenance
D $MW_{el,aux.pwr}$/MWth
E x…Heat generation capacity [20 MW_{th} … 250 MW_{th}]

4.1.2.3 Oil fired hot water tube boilers

Table 5: Overview of oil fired hot water tube boilers

	Unit	2015	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
A. Energy/technical data							**Lower**	**Upper**	**Lower**	**Upper**	A	1, 2, 4
Heat generation capacity	MW$_{th}$	20 - 250										
Total degree of utilization, nominal load	%	89	89	89	89	89	85	95	85	95		
Total degree of utilization, annual average	%	81	81	81	81	81					B, C	
Electricity consumption	%	0.7	0.7	0.6	0.6	0.5	0.5	1	0.3	0.8	D	
Technical lifetime	years	25	25	30	30	35	25	50	30	50		
Steam supply		-	-	-	-	-	-	(o)	-	(o)		
Hot water		o	o	o	o	o	(-)	o	(-)	o		
Warm water		(o)	(o)	(o)	(o)	(o)	(o)	o	(o)	o		
Low temperature		o	o	o	o	o	o	o	o	o		
B. Environmental data												5, 6, 7
CO2	g/MJ$_{th}$	80	80	80	80	80	50	100	50	100		
SO2	g/GJ$_{th}$	50	50	40	40	40	30	70	30	70		
NOX	g/GJ$_{th}$	10	10	8	8	5	7	15	2	10		
CH4	g/GJ$_{th}$	<	<	<	<	<						
N2O	g/GJ$_{th}$	<	<	<	<	<						
Particles	g/GJ$_{th}$	3	3	3	2	2	2	5	1	5		
C. Financial data												1, 3, 8
Quality of estimation		medium										
Nominal investment	M€/MW$_{th}$	0.12	0.12	0.12	0.12	0.12	0.08	0.16	0.08	0.16		
- of which equipment	M€/MW$_{th}$	0.08	0.08	0.08	0.08	0.08	0.05	0.11	0.05	0.11		
- of which installation	M€/MW$_{th}$	0.04	0.04	0.04	0.04	0.04	0.03	0.05	0.03	0.05		
Fixed O&M	k€/MW$_{th}$/a	2	2	1.9	1.9	1.8	1	5	1	5		
Variable O&M excl. electricity costs	€/MWh$_{th}$	0.3	0.3	0.3	0.3	0.3	0.1	0.5	0.1	0.5		
X. Technology specific data												
Cost function (estimation)	M€/MW$_{th}$	Invest(x)=$0.32x^{-0.20}$									E	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Workshop BOSCH: Fachseminar Auslegung und Planung von Thermischen Großanlagen
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6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 „Projektmanagement im Energiebereich“, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013

Notes:

A Oil (LHV appr. 42 MJ/kg) fired hot water tube boiler (6% O_2 flue gas)
B based on planned availability of 8 000 h/a (DH+GEN)
C uncertainty depending on (unplanned) maintenance
D $MW_{el,aux.pwr}/MW_{th}$
E x…Heat generation capacity [20 MW_{th} … 250 MW_{th}]

4.1.2.4 Biomass fired hot water tube boilers

Table 6: Overview of biomass fired hot water tube boilers

	Unit	2015	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
A. Energy/technical data							**Lower**	**Upper**	**Lower**	**Upper**	A	1, 2, 4, 9, 10
Heat generation capacity	$\mathrm{MW_{th}}$	20 - 250										
Total degree of utilization, nominal load	%	92	92	92	92	92	85	95	85	95		
Total degree of utilization, annual average	%	84	84	84	84	84					B, C	
Electricity consumption	%	1.6	1.6	1.5	1.5	1.5	1	2	1	2	D	
Technical lifetime	years	25	25	30	30	35	25	50	30	50		
Steam supply		-	-	-	-	-	--	-	--	-		
Hot water		o	o	o	o	o	(-)	o	(-)	o		
Warm water		(o)	(o)	(o)	(o)	(o)	(o)	o	(o)	o		
Low temperature		+	+	+	+	+	+	++	+	++		
B. Environmental data												5, 6, 7, 10
CO2	$\mathrm{g/MJ_{th}}$	110	110	110	110	110	50	150	50	150		
SO2	$\mathrm{g/GJ_{th}}$	5	5	5	5	5	0	20	0	20		
NOX	$\mathrm{g/GJ_{th}}$	90	90	80	80	70	50	150	30	100		
CH4	$\mathrm{g/GJ_{th}}$	<	<	<	<	<						
N2O	$\mathrm{g/GJ_{th}}$	<	<	<	<	<						
Particles	$\mathrm{g/GJ_{th}}$	4	4	4	3	3	2	6	2	6		
C. Financial data												1, 3, 8, 9, 11
Quality of estimation		medium										
Nominal investment	$\mathrm{M€/MW_{th}}$	0.3	0.3	0.3	0.28	0.26	0.25	0.35	0.2	0.35		
- of which equipment	$\mathrm{M€/MW_{th}}$	0.2	0.2	0.2	0.19	0.18	0.17	0.23	0.14	0.23		
- of which installation	$\mathrm{M€/MW_{th}}$	0.1	0.1	0.1	0.09	0.08	0.08	0.12	0.06	0.12		
Fixed O&M	$\mathrm{k€/MW_{th}/a}$	5	5	5	4	4	3	8	3	8		
Variable O&M excl. electricity costs	$\mathrm{€/MWh_{th}}$	0.2	0.2	0.2	0.2	0.2	0.1	0.5	0.1	0.5		
X. Technology specific data												
Cost function (estimation)	$\mathrm{M€/MW_{th}}$	$Invest(x)=0.80x^{-0.20}$									E	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
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7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 „Projektmanagement im Energiebereich", Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
9 Wien Energie: Biomasse Kraftwerk Simmering
10 Rechnungshofbericht Wien Energie Bundesforste Biomasse Kraftwerk
11 Wirtschaftlich effiziente Biomasse-Heizkraftwerke, Rolf Michler

Notes:

A Biomass (LHV appr. 14 MJ/kg) fired hot water tube boiler (6% O_2 flue gas)
B based on planned availability of 8000 h/a (DH+GEN)
C uncertainty depending on (unplanned) maintenance
D $MW_{el,aux.pwr}/MW_{th}$
E x…Heat generation capacity [20 MW_{th} … 250 MW_{th}]

4.1.2.5 Waste fired hot water tube boilers

Table 7: Overview of waste fired hot water tube boilers

	Unit	**2015**	**2020**	**2030**	**2040**	**2050**		**Uncertainty (2020)**		**Uncertainty (2050)**			**Note**	**Ref**
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**		A	1, 2, 4, 8, 10, 11
Heat generation capacity	MW_{th}	20 - 250												
Total degree of utilization, nominal load	%	89	89	90	90	91		85	95	85	95			
Total degree of utilization, annual average	%	81	81	81	82	83							B, C	
Electricity consumption	%	2.5	2.5	2.3	2.3	2.1		1	3	1	3		D	
Technical lifetime	years	25	25	30	30	35		25	50	30	50			
Steam supply		-	-	-	-	-		--	-	--	-			
Hot water		o	o	o	o	o		(-)	o	(-)	o			
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	o	(o)	o			
Low temperature		+	+	+	+	+		+	++	+	++			
B. Environmental data														5, 6, 7, 10, 11, 12
CO2	g/MJ_{th}	120	120	110	100	100		50	150	50	150			
SO2	g/GJ_{th}	10	10	8	6	5		0	20	0	20			
NOX	g/GJ_{th}	30	30	25	25	20		20	50	10	40			
CH4	g/GJ_{th}	<	<	<	<	<								
N2O	g/GJ_{th}	<	<	<	<	<								
Particles	g/GJ_{th}	5	5	4	4	3		3	7	2	5			
C. Financial data														1, 3, 9, 10
Quality of estimation		medium												
Nominal investment	$M€/MW_{th}$	0.5	0.5	0.4	0.4	0.4		0.3	0.6	0.3	0.6			
- of which equipment	$M€/MW_{th}$	0.3	0.3	0.26	0.26	0.26		0.2	0.4	0.2	0.4			
- of which installation	$M€/MW_{th}$	0.2	0.2	0.14	0.14	0.14		0.1	0.2	0.1	0.2			
Fixed O&M	$k€/MW_{th}/a$	10	10	9	9	8		8	20	5	15			
Variable O&M excl. electricity costs	$€/MWh_{th}$	0.3	0.3	0.3	0.3	0.3		0.1	0.5	0.1	0.5			
X. Technology specific data														
Cost function (estimation)	$M€/MW_{th}$	$Invest(x)=1.33x^{-0.20}$											E	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Workshop BOSCH: Fachseminar Auslegung und Planung von Thermischen Großanlagen
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6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 World Bank Technical Guidance Report – Municipal Solid Waste Incineration
9 „Projektmanagement im Energiebereich", Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 Operator's data (direct): Waste to Energy Plant Niklasdorf
11 Umweltbundesamt: Leitfaden zur Umweltverträglichkeitserklärung für Abfallverbrennungsanlagen, thermische Kraftwerke und Feuerungsanlagen; Report 0193; 2008
12 Umweltbundesamt: Stand der Technik bei Abfallverbrennungsanlagen

Notes:

A Solid waste (LHV appr. 13 MJ/kg) fired hot water tube boiler (6% O_2 flue gas)
B based on planned availability of 8 000 h/a (DH+GEN)
C uncertainty depending on (unplanned) maintenance
D $MW_{el,aux.pwr}/MW_{th}$
E x…Heat generation capacity [20 MW_{th} … 250 MW_{th}]

4.2 Electric boilers

Electric boilers are using electric energy directly to produce thermal power. Nowadays, there are two types of technologies mostly used in the district heating sector:

- Electric resistance boilers: Heat is generated by heating resistors. These elements are supplied by 400 V. Typical these types are used for small and medium sized applications ranging from several kW up to 10 MW.
- Electrode boilers: These boilers are consisting of an inner and an outer container. In the inner container two electrodes are located. They are connected to an AC (alternating current) medium voltage source (> 5kV). Heat is then generated between these electrodes by an ohmic resistance. Available modules can range up to 50 MW.

Figure 12: CAPEX breakdown of electric resistance boilers (excl. medium voltage connection)

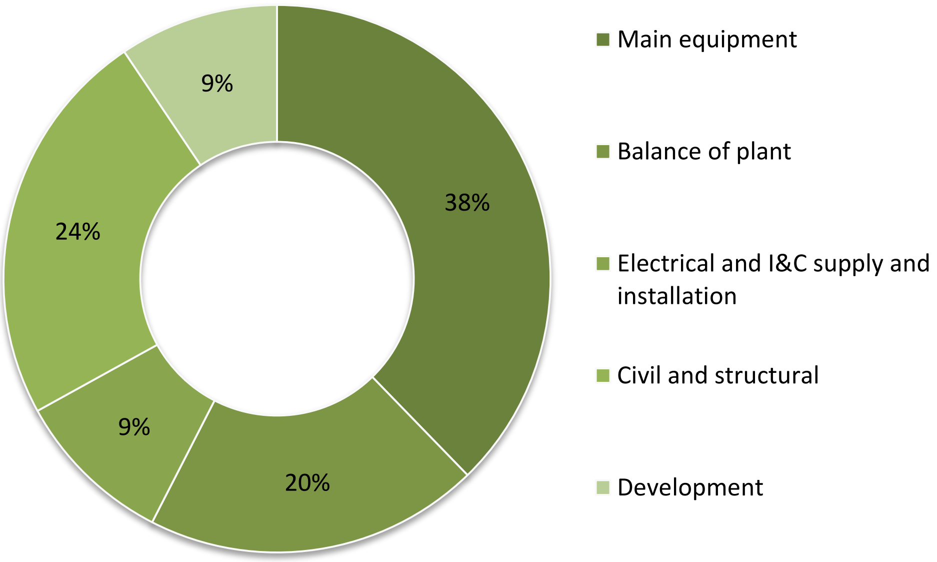


Table 8: Overview of electric boilers

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**			
Heat generation capacity	MW$_{th}$	1-30									A	
Total efficiency, nominal load	%	99	99	99	99	99		97	100			1,2
Total efficiency, annual average	%	98	98	98	98	98		96	99			1,2
Electricity consumption	%/MWth	101	101	101	101	101		100	103			1,2
Technical lifetime	years	20	20	20	20	20					B	1
Steam supply		o	o	o	o	o		o	o		C	
Hot water (up to 140°)		o	o	o	o	o		o	o		C	
Warm water (up to 105°C)		(o)	(o)	(o)	(o)	(o)		o	o			
Low temperature (up to 70°C)		o	o	o	o	o		o	o			
B. Environmental data												
CO2	g/MJ	-	-	-	-	-		-	-		D	
SO2	g/GJ	-	-	-	-	-		-	-		D	
NOX	g/GJ	-	-	-	-	-		-	-		D	
CH4	g/GJ	-	-	-	-	-		-	-		D	
N2O	g/GJ	-	-	-	-	-		-	-		D	
Particles	g/GJ	-	-	-	-	-		-	-		D	
C. Financial data												
Quality of CAPEX estimation		medium										
Nominal investment	M€/MW	0.12	0.12	0.12	0.12	0.12		0.06	0.20		E,C	1, 2, 3, 4
- of which equipment	M€/MW	0.08	0.08	0.08	0.08	0.08		0.04	0.12			1, 2, 3, 4
- of which installation	M€/MW	0.04	0.04	0.04	0.04	0.04		0.02	0.08			2, 3
Fixed O&M	T€/MW/a	0.5	0.5	0.5	0.5	0.5		0.3	0.7		F	1,2
Variable O&M excl. electricity costs	€/MWh	0.2	0.2	0.2	0.2	0.2		0.1	0.3		G	
X. Technology specific data												
Cost function (estimation)	M€/MW$_{th}$	Invest(x)=0.20$x^{-0.20}$									H	

References:
1 Manufacturer informations, 2015
2 Technology Data for Energy Plants, Danish Energy Agency , 2012 & 2016
3 Project information, 10 MW, Germany, 2014
4 Project information, 20 MW, Germany, 2015

Notes:
A Typical unit capacities: 1 to 10 MW for resistance boiler and 5 to 60 MW for electrode boiler
B Under good circumstances (water quality) and maintenance is a higher lifetime possible (+10 a)
C Units for Steam and Hot appr. 10 to 30% higher invest (due to 2014/68/EU requirements)
D Environmental impacts depends on how the used electricity is produced
E Additional costs for the connection to a 10 or 20 kV grid will be around 0.04 to 0.1 M€/MW (switchgear, transformer, additional space)
F Units for Steam and Hot appr. 50% higher O&M-costs (due to 2014/68/EU requirements)
G ILF/AIT calculations/estimations
H x…Heat generation capacity [1 MW_{th} … 30 MW_{th}]

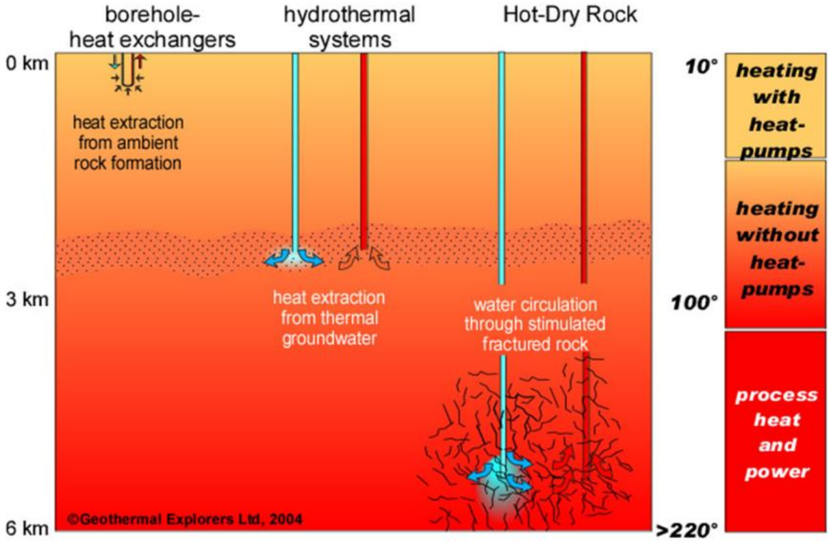
4.3 Geothermal plants

Geothermal heat is a natural renewable heat source. The geothermal energy comes from the residual heat from the earth's formation and for the most part from natural, radioactive decay products in the earth's crust. On average, the temperature in the earth increases by 3 K per 100 m. However, there are areas with geothermal anomalies where the temperature gradient is well above 100 K/km (e.g. Iceland and Tuscany). Such positive temperature anomalies are particularly advantageous for the use of geothermal energy.

For conceptioning a geothermal plant the heat transfer mechanisms in the reservoir must be understood. In addition to the pure heat conduction, heat transport can also be affected regionally by convection of circulating deep water. The geothermal heat can be taken either from hot water bodies (hydrothermal) or hot rock layers (petrothermal). This report deals with deep geothermal utilizations, that means drillings deeper than 400 m (usually over 1 000 m depth). Depending on the reservoir, a distinction is made between high enthalpy and low enthalpy deposits. Low enthalpy deposits are characterized by temperatures below 150 °C and primarily used for heat supply. Using binary methods also electricity generation is possible. High enthalpy deposits have temperatures above 200 °C and/or high pressures, which allows direct ("conventional") power generation.

Unfortunately, only few regions are suitable for geothermal applications. Currently geothermal DH systems are mostly used in China, France, Japan, Iceland, and the United States. In general, geothermal heat sources offer cheap running costs, high operation stability and long lifetime, low CO2 emissions and the ability for combination with heat storage. However, the investment costs are normally high and depend on the specific application, the heat source temperature, the distribution systems, and local parameters such as the labour costs. Moreover, this technology entails high risks because there is no security for success before the first well is drilled and the reservoir has been tested. A short distance between the heat source and heat demand area (city) represents a critical element for economy successfully geothermal DH applications. In regions with high geothermal potential, the usage of this resource for DH applications is often a cheap option and can be used for base-load coverages.

Figure 13: Methods of heat extraction depending on the different depth which has to be reached in order to extract heat from the reservoir

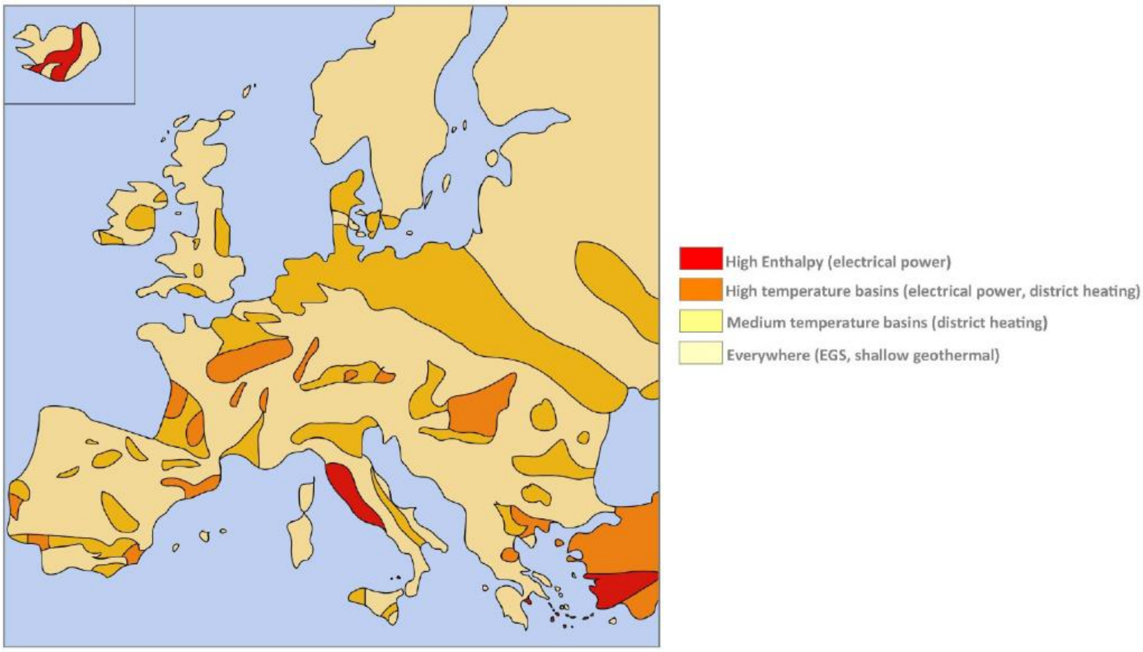


Source: Geothermal Explorers Ltd, 2004

The figure below gives an overview of the geothermal resources in Europe. It can be seen, that Iceland, Tuscany and Turkey has the best resources, where not only heat but also electricity generation could be possible.

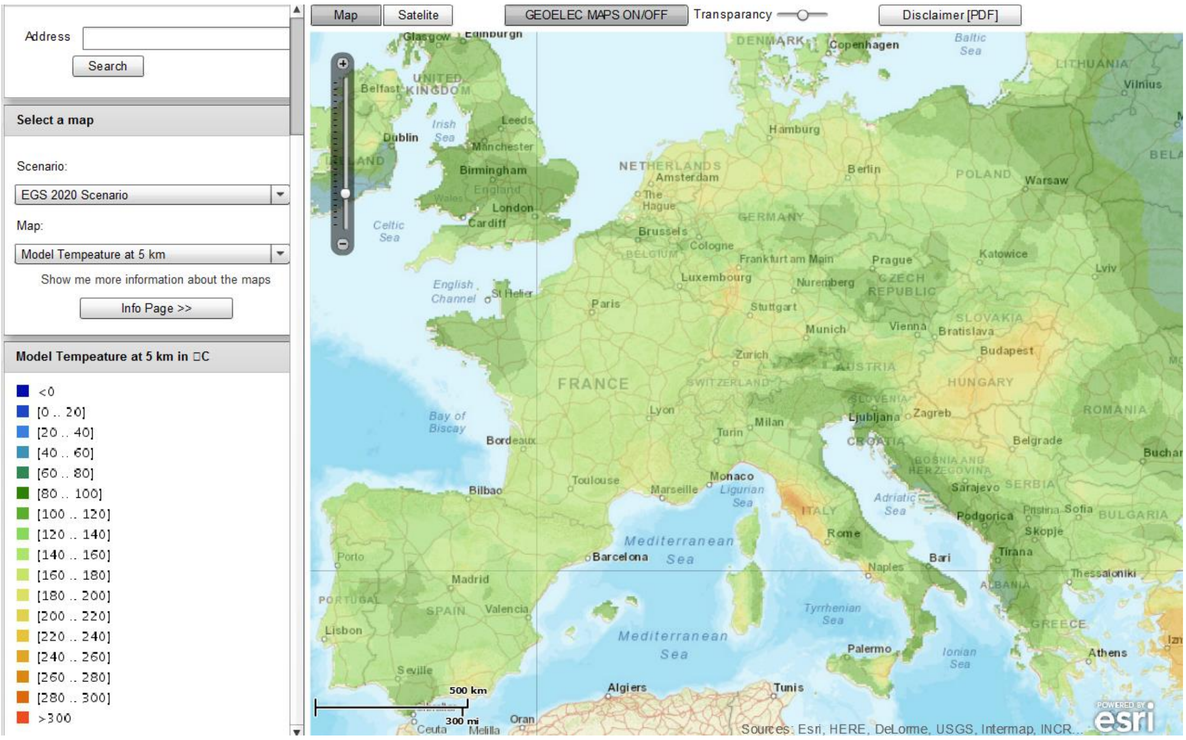
Using the next figure, respectively the internet link, modelled temperatures in different depths could be identified. Knowing the depth, in which the needed temperature could be found, the drilling costs could be calculated. Therefore, a cost function is given in the technology sheets.

Figure 14: Overview of geothermal resources in Europe



Source: EGEC - European Geothermal Energy Council

Figure 15: Modelled temperature at 5 km in °C



Select a map

Scenario: EGS 2020 Scenario

Map: Model Tempeature at 5 km

Show me more information about the maps

Info Page >>

Model Tempeature at 5 km in □C

- <0
- [0 .. 20]
- [20 .. 40]
- [40 .. 60]
- [60 .. 80]
- [80 .. 100]
- [100 .. 120]
- [120 .. 140]
- [140 .. 160]
- [160 .. 180]
- [180 .. 200]
- [200 .. 220]
- [220 .. 240]
- [240 .. 260]
- [260 .. 280]
- [280 .. 300]
- >300

Source: http://www.thermogis.nl/geoelec/ThermoGIS_GEOELEC.html

4.3.1 Hydrothermal plants

Hydrothermal geothermal energy describes the use of the energetic potential of low- (40 to 100 °C) or high-temperature (above 100 °C) deep water. In hydrothermal systems, water-bearing layers (aquifers) are present in the underground rock formations. The warm or hot thermal water is conveyed upwards, cooled in heat exchangers for the heat generation of district heating networks and then reinjected into the same aquifer layer at a sufficient distance. In Europe, practically only hydrothermal systems are used for heat only supply.

The main components of geothermal DH plants are, in addition to the production and injection wells, the pumps, heat exchangers and filter and slop systems. Also, coarse and fine filters are usually used to treat the thermal water. If the thermal water temperature is too low in comparison to the necessary heating supply temperature, auxiliary systems (e.g. peak boilers or heat pumps) are additionally required. The investment costs are mainly dominated through the drillings. The specific costs for a drilling could roughly be estimated to over EUR 1 000/m.

The CAPEX breakdown structure listed below differs from the definition of main equipment and balance of plant (BOP) to the others. For this technology, the drilling effort is taken into account with the balance of plant (BOP) in order to show the significant influence of the drilling on the total investment. Note: The presented cost distribution can vary widely from one project to another. Especially estimating the borehole costs, large uncertainties exist due to the limited availability of drilling rigs, changing feedstock prices (e.g. steel), unforeseen technological problems and on-site conditions.

Main equipment: Energy conversion plant with its main components like heat transfer station, heat exchangers, pumps, filters, etc.

Balance of plant: Borehole costs are dominating the overall investment costs and consists of seismics / preparatory arrangements, set up and recultivation of the drilling site, drilling lease (including personnel and energy costs), costs for drilling bits and mud (including the disposal of mud and cuttings) as well as logging and borehole completion.

Figure 16: CAPEX breakdown of hydrothermal direct use plants

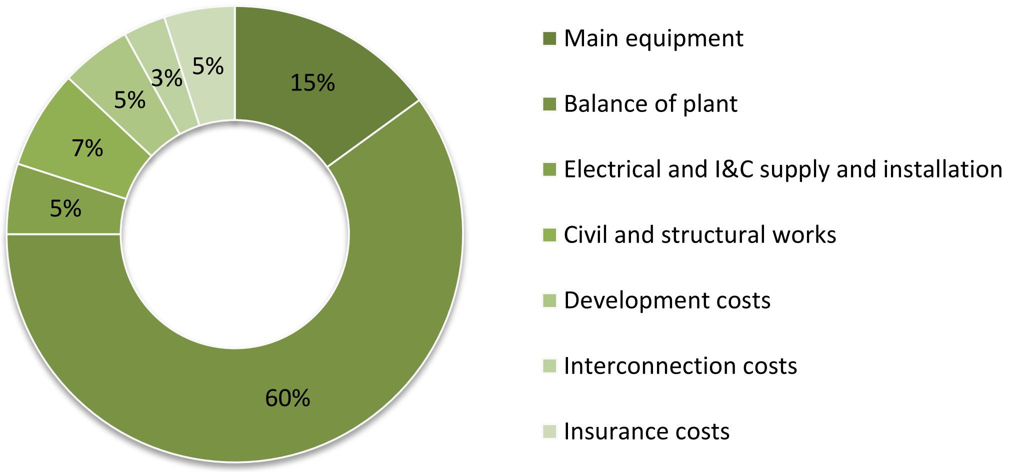


Table 9: Overview of hydrothermal direct use plants

	Unit	**2015**	**2020**	**2030**	**2040**	**2050**		**Uncertainty (2020)**		**Uncertainty (2050)**			**Note**	**Ref**
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Heat generation capacity	MW$_{th}$	1 - 50											A	1, 2, 3, 4, 5
Total efficiency, nominal load	%	Not applicable												
Electricity consumption	%/MW$_{th}$	2	2	2	2	2		1	4	1	4		B	6, 7
Technical lifetime	years	25	25	25	25	25		20	>25	20	>25		C	1, 2, 5
Steam supply		N/A	N/A	N/A	N/A	N/A							D	
Hot water		(-)	(-)	(-)	(-)	(-)		-	o	-	o			
Warm water		(o)	(o)	(o)	(o)	(o)		-	o	-	o		E	
Low temperature		(+)	(+)	(+)	(+)	(+)		o	+	o	+			
B. Environmental data														
CO2	g/MJ$_{th}$	0	0	0	0	0							F	8
SO2	g/GJ$_{th}$	0	0	0	0	0								
NOX	g/GJ$_{th}$	0	0	0	0	0								
CH4	g/GJ$_{th}$	0	0	0	0	0								
N2O	g/GJ$_{th}$	0	0	0	0	0								
Particles	g/GJ$_{th}$	0	0	0	0	0								
C. Financial data														
Quality of CAPEX estimation		medium												
Learning rate	%	5											G	4
Nominal investment	M€/MW$_{th}$	1.30	1.25	1.20	1.15	1.10		0.8	1.5	0.7	1.3		H	1, 5, 9, 10, 11, 12, 13
- of which equipment	M€/MW$_{th}$	0.39	0.38	0.36	0.35	0.33		0.25	0.50	0.22	0.44		I	7
- of which installation	M€/MW$_{th}$	0.91	0.87	0.84	0.80	0.77		0.75	1.00	0.66	0.88			7
Fixed O&M	k€/MW$_{th}$/a	26	25	24	23	22		21.5	32.4	19.1	28.5		J	1, 5, 7, 11
Variable O&M excl. electricity costs	€/MWh$_{th}$	N/A	N/A	N/A	N/A	N/A								
X. Technology specific data														
Cost function (estimation)	M€/MW$_{th}$	$Invest(x)=2.88x^{-0.34}$											K	
Cost function drilling (estimation)	€/m	$C_{Drilling}(Depth) = 0.152 * (Depth) + 785$											L	9, 13, 14, 15
Construction time	months	4	4	4	4	4		3	>6	3	>6		M	9, 13
Capacity factor	%	30 - 45											N	7, 11, 16
Production rate	l/s	20 - 150											O	9, 16, 17
Typical drilling depth	m	1 000 - 3 000											P	3, 7, 16
Reservoir temperature	°C	80 - 120											Q	3, 16, 17
Average daily drilling capacity	m/day	40						<20 - 60					R	4, 9

References:

1 Developing geothermal district heating in Europe; GeoDH, 2014
2 District Heating; IEA-ETSAP and IRENA, January 2013
3 Tiefe Geothermie; ASUE, June 2011
4 Renewable Energy in Europe - Markets, Trends and Technologies; EREC, 2010
5 Financing Renewable Energy in the European Energy Market; Ecofys, January 2011
6 Potenzial der Tiefengeothermie für die Fernwärme- und Stromproduktion in Österreich; Koenighofer, June 2014
7 Erneuerbare Energien - Systemtechnik, Wirtschaftlichkeit, Umweltaspekte; M. Kaltschmitt et al., 2013 © Springer-Verlag Berlin Heidelberg
8 Geothermal Power Plants: Principles, Applications, Case Studies and Environmental Impact; R. DiPippo, 2012
9 Geothermieprojekt Ried - Wärme und Kälte aus Geothermie und Umgebungswärme; Fuereder, April 2012
10 Geothermal Heat and Power; IEA-ETSAP, May 2010
11 Technology Roadmap - Geothermal Heat and Power; OECD/IEA, May 2011
12 Renewables for Heating and Cooling - Untapped Potential; OECD/IEA, July 2007
13 Geothermie-Projekt Pullach Daten und Fakten - IEP, May 2008
14 Enhanced Geothermal Systems (EGS) Well Construction Technology Evaluation Report; Sandia Report, December 2008
15 New Geothermal Site Identification and Qualification; GeothermEx, April 2004
16 Regenerative Energietechnik; V. Wesselak et al., May 2013 © Springer-Verlag Berlin Heidelberg
17 Economic analysis of geothermal energy provision in Europe (Workpackage 5 – Deliverable D35); ENGINE, October 2007

Notes:

A The first regions using geothermal district heating systems (geoDH) were those, with the best hydrothermal potential. However, new technologies and systems increased the number of regions developing this utilization. System capacities range from small (0.5 - 2 MW_{th}) to larger up to 50 MW_{th}.
B Pumping effort could be counted up to 2 % of the heat power from the geothermal water.
C The technology has a long life time period with at least 20 but commonly up to 30 years (e.g. the doublet wells of Thisted in Denmark have been in operation for 30 years).
D High temperature heat supply is not common as normally temperatures below 120 °C are exploited. If higher reservoir temperatures are gained, usually CHP applications will be used (see chapter Geothermal CHP).
E The supply temperature is mainly defined by the reservoir temperature. If higher temperatures are needed, deeper drillings are necessary. If the boreholes do not deliver the expected capacities, auxiliary heating systems could be installed.
F Closed loop plants emit no gaseous emissions during operation.
G A learning rate is not really seen as the technology and the used components are far developed. Nevertheless, drillings could have the biggest cost reduction potential. On the one hand through faster drilling methods and on the other hand through better exploration (further developed seismic methods could increase the success rate and additionally decrease risk and insurance costs).
H Geothermal district heating systems are capital intensive and the production and injection wells consumes the highest part with up to 70 % of the initial investment costs. The cost estimation is based on a 10 MW_{th} geothermal plant and includes also downhole and circulation pumps, heat exchangers, interconnection, control equipment and building retrofit. Auxiliary heating system (e.g. peak load boiler) and DH network / distribution is not included. The cost reduction is mainly assumed due to better forecasting (reducing the risk and insurance costs) and drilling methods.
I The highest effort is incurred on-site mainly caused by drilling work.
J Operating expenses are much lower than in conventional systems, consisting of system maintenance, personnel (operation and control) and insurance.
K Cost function is developed through cost comparison of realised plants. x…Heat generation capacity [1 MW_{th} … 50 MW_{th}]
L An investigation of realised projects in middle Europe shows up drilling costs between EUR 1 100 - 1 300/m at depths 2 000 - 3 000 m and is affirming the rough estimation by the formula. Note: Given cost function is just for one borehole.

M Only the drilling time for the drilling doublet.

N Geothermal heating units are base load plants and the capacity factor is given through the district heating grid. Normally DH-grids have full load hours up to 4 000 h/a. Peak load boilers (often fossil fuel) are used to meet the coldest period, rather than drilling additional wells or pumping more fluids, as geothermal usually meets at least 50 and up to 90 % of the time, thus improving the efficiency and economics of the system.

O Higher production rates leads to higher pumping effort which decreases the system efficiency.

P Typical drilling depths ranges from 1 000 - 3 000 but in some cases also more than 3 500 m. Larger depths make the geothermal heat only application increasingly uneconomical.

Q If the reservoir temperature is too low for direct usage, auxiliary systems (e.g. peak boiler, heat pump, etc.) has to be used.

R A value of 44 m/day was reached in the project "Ried" (Ref. 9). Note: Depending on the rock formation, daily drilling performance could vary a lot.

4.3.2 Low temperature hydrothermal plants with heat pump

Heat from deep reservoirs can be utilized directly through a heat exchanger. On the one hand increasing drilling depths lead to higher temperatures but on the other hand also to higher pumping costs. From an economically point of view, therefore it could be more attractive to use heat pumps and extract heat from higher reservoirs instead of direct usage. Especially if high drilling costs should be avoided, or the reservoir temperature is too low. The heat pumps can either be driven by electrical (compressor) or by heat (absorption). The geothermal water is saline that is why a separation circuit is used. Through a production well, warm geothermal water is pumped to the surface where heat is exchanged and pumped back into the reservoir via an injection well. To avoid premature cooling, an appropriate distance is needed between the production and injection wells. Heat pumps could act as an auxiliary heating unit through lifting the temperature to the required level and simultaneously increase the heat extraction through cooling down the reinjected water. In some cases the cooling by heat pumps can help to reduce gas separation (from the water) and avoid precipitation, which may cause clogging the reinjection well. A best practice example is located in Thisted, Denmark which two geothermal wells were drilled back in the early 1980'ies.

The CAPEX breakdown structure listed below differs from the definition of main equipment and balance of plant (BOP) to the others. For this technology, the drilling effort is taken into account with the balance of plant (BOP) in order to show the significant influence of the drilling on the total investment. Note: The presented cost distribution can vary widely from one project to another. Especially estimating the borehole costs, large uncertainties exist due to the limited availability of drilling rigs, changing feedstock prices (e.g. steel), unforeseen technological problems and on-site conditions.

Main equipment: Energy conversion plant with its main components like heat transfer station, heat pump(s), heat exchangers, pumps, filters, etc.

Balance of plant: Borehole costs are dominating the overall investment costs and consists of seismics / preparatory arrangements, set up and recultivation of the drilling site, drilling lease (including personnel and energy costs), costs for drilling bits and mud (including the disposal of mud and cuttings) as well as logging and borehole completion.

Figure 17: CAPEX breakdown of low temperature hydrothermal only heating plants with heat pump

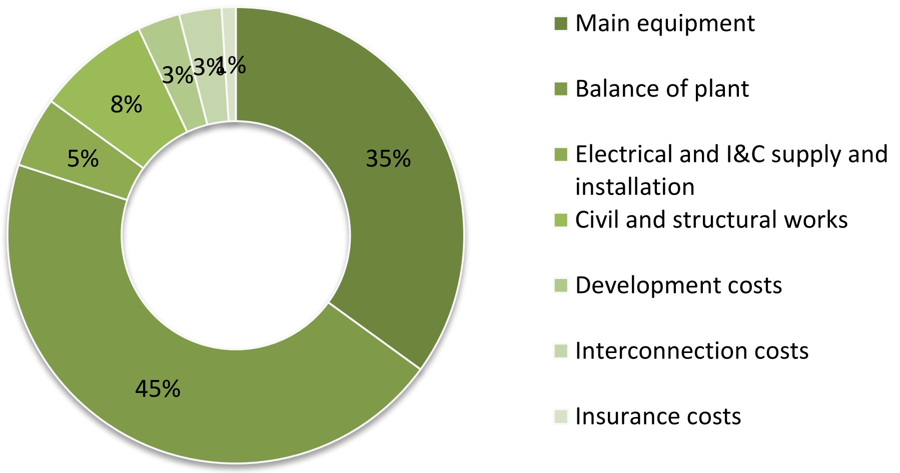


Table 10: Overview of low temperature hydrothermal only heating plants with heat pump

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Heat generation capacity	MW$_{th}$	1 - 50											A	1
Total efficiency, nominal load	%	Not applicable												
Electricity consumption	%/MW$_{th}$	2	2	2	2	2		1	4	1	4		B	1
Technical lifetime	years	25	25	25	25	25		20	>25	20	>25		C	1, 2
Steam supply		N/A	N/A	N/A	N/A	N/A							D	
Hot water		N/A	N/A	N/A	N/A	N/A								
Warm water		-	-	-	-	-		--	-	--	-		E	
Low temperature		o	o	o	o	o		o	o	o	o			
B. Environmental data														
CO2	g/MJ$_{th}$	0	0	0	0	0							F	
SO2	g/GJ$_{th}$	0	0	0	0	0								
NOX	g/GJ$_{th}$	0	0	0	0	0								
CH4	g/GJ$_{th}$	0	0	0	0	0								
N2O	g/GJ$_{th}$	0	0	0	0	0								
Particles	g/GJ$_{th}$	0	0	0	0	0								
C. Financial data														
Quality of CAPEX estimation		medium											G	
Learning rate	%												H	
Nominal investment	M€/MW$_{th}$	1.25	1.22	1.20	1.10	1.00		1.00	1.60	0.70	1.40		I	1, 2, 3, 4
- of which equipment	M€/MW$_{th}$	0.50	0.49	0.48	0.44	0.40		0.43	0.61	0.35	0.50		J	
- of which installation	M€/MW$_{th}$	0.75	0.73	0.72	0.66	0.60		0.61	0.79	0.50	0.65			
Fixed O&M	k€/MW$_{th}$/a	30	29	27	26	25		20	40	20	30		K	1, 4, 5
Variable O&M excl. electricity costs	€/MWh$_{th}$	N/A	N/A	N/A	N/A	N/A								
X. Technology specific data														
Cost function (estimation)	M€/MW$_{th}$	$Invest(x)=1.60x^{-0.11}$											L	
Cost function drilling (estimation)	€/m	$C_{Drilling}(Depth) = 0.152 * (Depth) + 785$											M	6, 7
Capacity factor	%	60 - 80											N	
Production rate	l/s	10 - 50											O	
Typical drilling depth	km	2	2	2.5	2.5	3							P	1
Reservoir temperature	°C	30 - 80												1
Average daily drilling capacity	m/day	50						40 - >60					Q	

References:

1 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Energinet.dk, May 2012
2 District Heating; IEA-ETSAP and IRENA, January 2013
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4 Cost analysis of district heating compared to its competing technologies; O. Gudmundsson et al., 2013 © WIT Transactions on Ecology and The Environment, Vol. 176
5 Erneuerbare Energien - Systemtechnik, Wirtschaftlichkeit, Umweltaspekte; M. Kaltschmitt et al., 2013 © Springer-Verlag Berlin Heidelberg
6 New Geothermal Site Identification and Qualification; GeothermEx, April 2004
7 Enhanced Geothermal Systems (EGS) Well Construction Technology Evaluation Report; Sandia Report, December 2008

Notes:

A The geothermal heat source and the heat pump roughly contribute to equal shares.
B The electrical consumption for the plant (pump, control etc.) could be counted with approx. 2 %. If an electrical heat pump is used, this electrical consumption has additional to be taken into account (depending on the COP).
C The drillings have a long life time period, but maybe the heat pump has to be replaced earlier.
D High temperature heat supply is against the concept with heat pumps and therefore not used.
E Mainly low temperature applications are preferred as the heat pump is normally used to increase the temperature to its needed level. That is why, the efficiency goes down with increasing temperatures.
F Closed loop plants emit no gaseous emissions during operation, which makes the utilization of geothermal energy very CO_2 friendly.
G Although not so much deep geothermal systems using heat pumps exist, the CAPEX estimation is set "medium" as costs for hydrothermal plants and heat pumps are known and the described system is a combination of both.
H The technology uses standard components. A learning rate is mostly seen, if the market for large heat pumps is further increasing.
I The cost estimation includes downhole and circulation pumps, heat exchangers, interconnection, control equipment, building retrofit and heat pumps. Auxiliary heating system (e.g. peak load boiler) and DH network / distribution is not included. The cost reduction is mainly assumed due to better forecasting (reducing the risk and insurance costs) and drilling methods and a reduction of prices for large heat pumps.
J The highest effort is incurred on-site mainly caused by drilling work. In comparison to the direct use of hydrothermal energy, the equipment share is slightly increasing caused by the heat pump.
K Operating expenses consists of system maintenance, personnel (operation and control) and insurance.
L Cost function is just an estimation (mainly based on cost development of heat pumps and their total cost share) due to the lack of reference projects. x…Heat generation capacity [1 MW_{th} … 50 MW_{th}]
M Due to the lower drilling depths, the costs could roughly estimated between EUR 900 - 1 200/m at depths 800 - 2 000 m.
N The combination of geothermal heat and heat pumps allows better operation modes which increases the capacity factor.
O Higher production rates leads to higher pumping effort which decreases the system efficiency.
P As investment and pumping costs increase with the depth, the usage of heat pumps could be an economically attractive option to extract heat from higher reservoirs with lower temperatures. Typical depths ranges from 800 - 2 000 (in some cases up to 3 000) m where temperatures from 30 - 80 °C could be expected.
Q Higher average daily drilling capacities could be reached owing to lower drilling depths.

4.3.3 Enhanced geothermal system plants

Enhanced Geothermal System (EGS) are often referred to as HDR (hot dry rock) systems or with the neutral term petrothermal systems. At the moment EGS technologies are very cost intensive, but potential is seen to produce large amounts of electricity almost anywhere in the world, especially in regions without hydrothermal reservoirs, cost-effectively. This system is used if the rock in which the high temperatures have been found is not very permeable, so that no water can be extracted from it, an artificially introduced heat transfer medium (water or CO_2) can be circulated between two deep wells in an artificially created rupture system. First, water is injected into the gland system (with at least one injection hole) into the rock under a pressure that must be so far above the petrostatic pressure that the minimum main stress in the respective depth layer is exceeded (hydraulic stimulation or fracturing). As a result, flow paths are broken up or existing ones are expanded and thus the permeability of the rock is increased. This procedure is necessary, as otherwise the heat transfer area and the continuity would be too small. Subsequently, this system of natural and artificial cracks forms an underground, geothermal heat exchanger. By the second (production) hole the carrier medium is conveyed back to the surface. In Europe only three Enhanced Geothermal Systems are being tested in the pilot projects in Soultz-sous-Forêts (F), in Bad Urach (D) and in Basel (CH). The method of hydraulic fracturing is controversial, since small (barely noticeable) earth vibrations (induced seismicity) are possible in projects of deep geothermal energy during the stimulation phase (high pressure stimulation). As there occurred some problems in Bad Urach (financing/drilling issues) and in Basel (discontinued due to quake) it was decided not to continue these two projects.

At the moment no EGS plant for only heating utilization exists, and hence the data basis for the table below is not very strong and it is questionable whether in the near future only EGS heating systems will be built and if they are economically feasible. In order to provide figures for an EGS heating plant, data from the CHP plant of Soultz-sous-Forêts are used and analogical modified.

The CAPEX breakdown structure listed below differs from the definition of main equipment and balance of plant (BOP) to the others. For this technology, the drilling effort is taken into account with the balance of plant (BOP) in order to show the significant influence of the drilling on the total investment. Note: The presented cost distribution can vary widely from one project to another. Especially estimating the borehole costs, large uncertainties exist due to the limited availability of drilling rigs, changing feedstock prices (e.g. steel), unforeseen technological problems and on-site conditions.

Main equipment: Energy conversion plant with its main components like heat transfer station, heat exchangers, pumps, filters, etc.

Balance of plant: Borehole costs are dominating the overall investment costs and consists of seismics / preparatory arrangements, set up and recultivation of the drilling site, drilling lease (including personnel and energy costs and reservoir stimulation / hydraulic fracturing), costs for drilling bits and mud (including the disposal of mud and cuttings) as well as logging and borehole completion.

Figure 18: CAPEX breakdown of enhanced geothermal system only heating plants

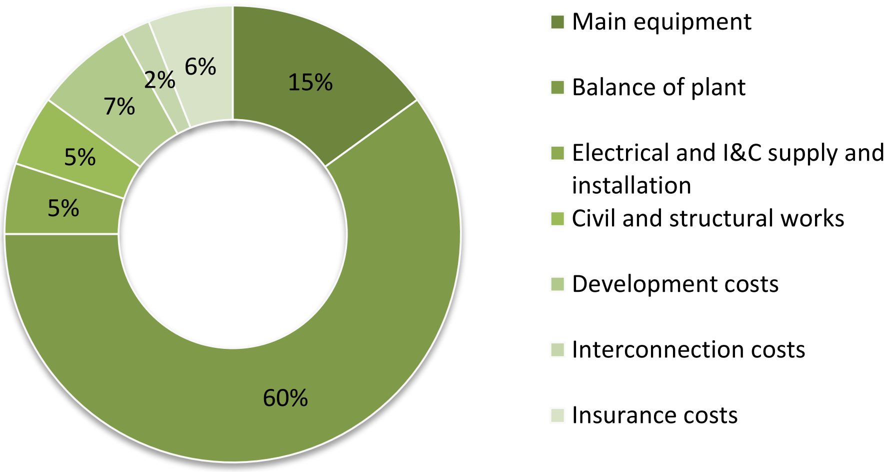


Table 11: Overview of enhanced geothermal system only heating plants

	Unit	2015	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
A. Energy/technical data							**Lower**	**Upper**	**Lower**	**Upper**		
Heat generation capacity	MW$_{th}$	> 10									A	
Total efficiency, nominal load	%	Not applicable										
Electricity consumption	%/MW$_{th}$	3	3	3	3	3	2	6	2	6	B	
Technical lifetime	years	30	30	30	30	30	25	>30	25	>30	C	1
Steam supply		N/A	N/A	N/A	N/A	N/A					D	
Hot water		(-)	(-)	(-)	(-)	(-)	-	o	-	o		
Warm water		(o)	(o)	(o)	(o)	(o)	-	o	-	o		
Low temperature		(+)	(+)	(+)	(+)	(+)	o	+	o	+		
B. Environmental data												
CO2	g/MJ$_{th}$	0	0	0	0	0					E	
SO2	g/GJ$_{th}$	0	0	0	0	0						
NOX	g/GJ$_{th}$	0	0	0	0	0						
CH4	g/GJ$_{th}$	0	0	0	0	0						
N2O	g/GJ$_{th}$	0	0	0	0	0						
Particles	g/GJ$_{th}$	0	0	0	0	0						
C. Financial data												
Quality of CAPEX estimation		low									F	
Learning rate	%										G	
Nominal investment	M€/MW$_{th}$	3.5	3.3	3.0	2.8	2.5	2.5	5.0	1.5	3.5	H	1, 2, 3, 4
- of which equipment	M€/MW$_{th}$	1.05	1.00	0.90	0.84	0.75	0.66	1.32	0.50	1.00	I	
- of which installation	M€/MW$_{th}$	1.45	2.30	2.10	1.96	1.75	1.98	2.64	1.50	2.00		
Fixed O&M	k€/MW$_{th}$/a	20	19	18	16	15	15	25	10	20	J	5
Variable O&M excl. electricity costs	€/MWh$_{th}$	N/A	N/A	N/A	N/A	N/A						
X. Technology specific data												
Cost function (estimation)	M€/MW$_{th}$	Invest(x)=$6.22x^{-0.25}$									K	
Construction time	months	6	6	6	5	5	5	8	4	7	L	1
Typical drilling depth	km	6	6	7	8	10					M	
Reservoir temperature	°C	> 150									N	6
Cost function drilling	€/m	$C_{Drilling}$(Depth) = 2 500 * (Depth)									O	1
Average daily drilling capacity	m/day	< 40									P	

References:

1 Geothermal Investment Guide; GeoElec (Project Deliverable 3.4), November 2013
2 Factsheets on Geothermal Electricity; GeoElec, 2013
3 Towards more Geothermal Electricity Generation in Europe; GeoElec (Final Report), 2013
4 Projected Costs of Generating Electricity; IEA, September 2015
5 Cost of Electricity from Enhanced Geothermal Systems; S. K. Sanyal et al., January 2007
6 Integral modeling and financial impact of the geothermal situation and power plant at Soultz-sous-Forets; P. Heidinger, January 2010 (C. R. Geoscience 342 (2010) 626–635)

Notes:

A It is assumed to achieve high heat capacities in order to build economic feasible Enhanced Geothermal Systems (EGS) heat plants.
B In comparison to conventional geothermal plants the pumping effort will be slightly higher owing to the required fracturing pressure.
C Long life time with over 30 years is assumed.
D The supply temperature is mainly defined by the reservoir temperature. If higher temperatures are needed, deeper drillings are necessary. If the boreholes do not deliver the expected capacities, auxiliary heating systems could be installed. In general EGS is a technology with deep drillings to exploit high temperature reservoirs. Therefore, high temperature heat supply should be possible but will strongly influence both efficiency and costs.
E EGS works at least with two wells (injection and production). Hence the closed loop, these plants should not emit gaseous emissions during operation.
F The CAPEX estimation is very low, as there exists very few CHPs and no one "heat-only"-EGS plant.
G Learning rate figures could not be given at the moment as there has to be still done some research issues and developments. Note: The Google Foundation sees EGS as a technology that could be used as a source of energy on a large scale in the future, thus supporting the development of EGS with several million US dollars.
H Cost estimation is mostly done on the given case study "EGS project in Germany" and under further consideration of the listed references. In the case study a binary plant (ORC) was considered, which was excluded for the heat only cost estimation. According to Ref. 2, drilling represents more than half of the total cost of enhanced geothermal systems.
I The highest effort is incurred on-site mainly caused by drilling work and hydraulic fracturing.
J The authors of Ref. 6 assume lower O&M costs in comparison to conventional geothermal systems. The assumption is based on that EGS projects will have more controlled and optimized production/injection operation, absence of make-up well drilling, and relatively small number of well workovers expected in an EGS operation.
K Cost function is just an estimation due to the lack of reference projects. x…Heat generation capacity [>10 MW_{th}]
L Due to the higher stimulation and hydraulic fracturing effort, longer construction time is assumed.
M EGS may extract heat from depths of 4 - 6 km and predictions assume 10 km wells in the future to exploit high temperature sources.
N Due to the high effort of EGS, deeper drillings are assumed with temperatures over 150 °C. E.g. At the EGS plant Soultz-sous-Forets the temperature is 200 °C in depth of 5 000 m (Ref. 6).
O The case study in Ref. 1 assumes drilling costs of approx. EUR 2 500/m and well. The higher costs can be substantiated by greater depths and higher temperatures (need for higher material resistances).
P It is assumed that the average daily drilling capacity of EGS projects is lower to conventional geothermal projects as deeper drillings are necessary.

4.4 Solar thermal

Comparing the specific energy yield per square meter collector area, solar thermal energy has a higher yield value than other technologies.

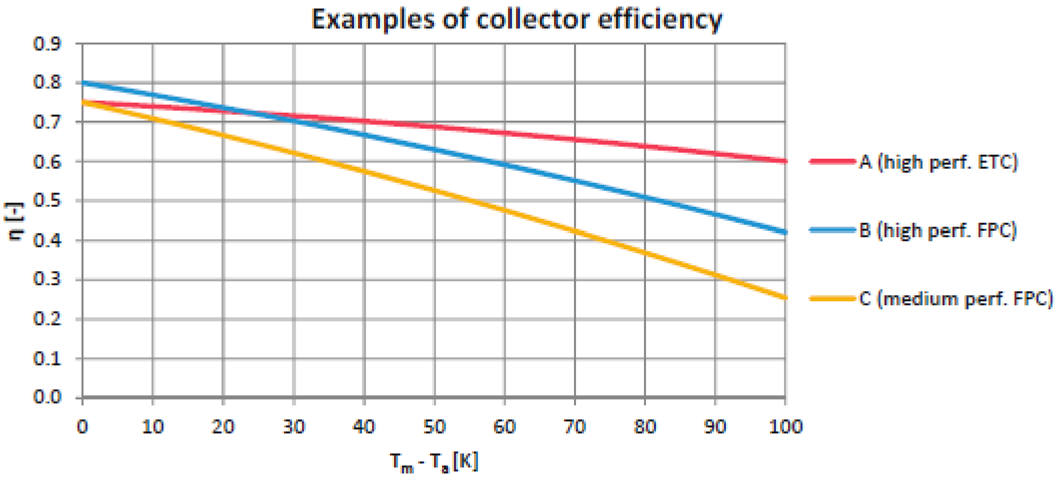
Feeding in of large heat amounts from solar systems into large district heating networks (also known as SDH – solar district heating) is, however, not easily possible, since even the lower grid temperatures during summer operation of the district heating supply can often not be achieved by solar thermal energy even under efficient conditions. In the case of solar thermal, there is also the problem of the seasonal oppositeness of heat supply and demand. As solar thermal systems supply most of their generated energy during the summer months, the challenge is to store at least some of the heat generated during the colder season in seasonal heat storage. Further challenges could be limited feed-in capacities given by the network and the required space. Even the need for space is often a logistical obstacle. It is most likely that conversions or industrial traps are likely to be accessible (with a reasonable financial burden) if there is a suitable location for the heating network (contaminated sites). Open spaces for the arrangement of solar thermal systems with several thousand m² of collector area are mostly not available - especially in urban centres. Typical space requirement for a free-standing solar thermal system is between 3-4 m² per collector area.

Common types are flat plate collectors (FPC) without vacuum and evacuated tubular collectors with compound parabolic concentrator (ETC-CPC). The differences between these two types are explained below. Figure 19 illustrates how the efficiency parameters and the collector mean temperature affect the efficiency. Type "A" corresponds to a high performing ETC-CPC, type "B" to a FPC with treated cover glass and convection barrier and "C" to a cheaper FPC without treatment or convection barrier. The figure shows, that in this example type "B" is good at medium to high temperatures and type "C" is good at low temperatures. Although the ETC-CPC is best at higher collector temperatures, in many SDH plants FPC have been chosen instead of ETC because of the better price/performance ratio.

In most SDH systems a mixture of water and glycol (determined by the minimum ambient temperature of the given location) is used as collector fluid, which lowers the freezing point. The disadvantage of glycol is that it decreases the efficiency due to the higher viscosity and lower heat capacity.

Another approach is to dispense with the antifreeze mixture and heat up the solar circuit through the DH grid when it is necessary. This consumes approx. 1–2 % of the yearly energy output of the solar plant.

Figure 19: Examples of collector efficiency based on aperture area as function of temperature difference between collector fluid and ambient air. Total solar irradiation is 1 000 W/m² on the collector plane.



Source: Solar district heating guidelines

4.4.1 Flat plate collector

Flat plate collectors operate at an average temperature of approx. 80 °C. In them the light is not bundled, but directly heats a flat heat-absorbing surface which conducts heat well and is traversed with tubes containing the heat transfer medium. In these collectors, a water-propylene glycol mixture (ratio 60:40) is usually used as heat transfer medium. The addition of 40 percent propylene glycol achieves frost protection down to -23 ° C and below freezing without volume increase (to avoid possible frost bumping), as well as a boiling temperature that may be 150 °C or more depending on the pressure.

Figure 20: CAPEX breakdown of solar thermal heating plants with flat plate collectors

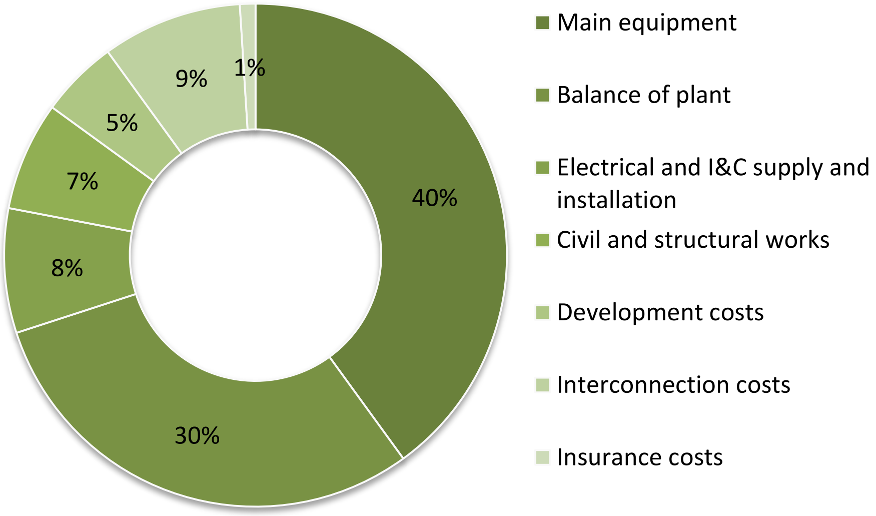


Table 12: Overview of solar thermal heating plants with flat plate collectors

	Unit	2015	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
A. Energy/technical data							**Lower**	**Upper**	**Lower**	**Upper**		
Collector area	m²	500 - 50 000									A	1, 2
Annual collector yield	MWh/(m².a)	0.373	0.374	0.375	0.376	0.377	0.338	0.665	0.340	0.680	B	3, 4
Total efficiency, annual average	%	34.2	34.3	34.4	34.5	34.6	33	43	35	46	C	3
Electricity consumption	%/MWth	1	1	1	1	1	0.6	1.4	0.7	1.3	D	1, 5
Technical lifetime	years	25	25	30	30	30	20	35	25	35	E	1, 5, 6
Steam supply		N/A	N/A	N/A	N/A	N/A					F	
Hot water		N/A	N/A	N/A	N/A	N/A						
Warm water		--	--	--	--	--	--	-	--	-		
Low temperature		(o)	(o)	(o)	(o)	(o)	o	+	o	+	G	
B. Environmental data												
CO2	g/MJ$_{th}$	0	0	0	0	0						
SO2	g/GJ$_{th}$	0	0	0	0	0						
NOX	g/GJ$_{th}$	0	0	0	0	0						
CH4	g/GJ$_{th}$	0	0	0	0	0						
N2O	g/GJ$_{th}$	0	0	0	0	0						
Particles	g/GJ$_{th}$	0	0	0	0	0						
C. Financial data												
Quality of CAPEX estimation		high										
Learning rate	%										H	
Nominal investment	M€/MW$_{th}$	0.482	0.475	0.465	0.455	0.435	0.420	0.530	0.380	0.480	I	1, 4, 6, 7, 8
- of which equipment	M€/MW$_{th}$	0.337	0.333	0.326	0.319	0.305	0.309	0.380	0.283	0.348		1, 6, 8, 9
- of which installation	M€/MW$_{th}$	0.145	0.142	0.139	0.136	0.130	0.095	0.166	0.087	0.152	J	1, 6, 8, 9
Fixed O&M	k€/MW$_{th}$/a	1.8	1.7	1.6	1.5	1.4	1.0	2.4	0.9	2.1	K	1, 7
Variable O&M excl. electricity costs	€/MWh$_{th}$	N/A	N/A	N/A	N/A	N/A					L	1, 6, 7
X. Technology specific data												
Cost function (estimation)	€/m²	$C_{FPC}(A_{Coll})$ = 1 535 * (Collector Area)^(-0.165)									M	5, 8, 10
Cost function (estimation)	M€/MW$_{th}$	Invest(x)=$0.661x^{-0.165}$									N	5, 8, 10
Construction time	months	4	4	3	3	3	2	5	2	5	O	1, 6

References:

1 S.O.L.I.D. Gesellschaft für Solarinstallation und Design mbH (http://www.solid.at/en/)

2 Ranking List of European Large Scale Solar Heating Plants; Solar District Heating (SDH), December 2016 (http://solar-district-heating.eu/ServicesTools/Plantdatabase.aspx)

3 SDH Online-Rechner (Online calculator for a quick feasibility study of solar district heating including seasonal storage); Solites (Steinbeis Forschungsinstitut für solare und zukunftsfähige thermische Energiesysteme), 2013 (http://www.sdh-online.solites.de/)

4 Solar district heating guidelines - Collection of fact sheets; SDH, August 2012 (http://solar-district-heating.eu/)

5 Technology and Demonstrators - Technical Report Subtask C - Part C1; IEA SHC Task 52 Solar Heat and Energy Economics in Urban Environments, January 2016

6 Manufacturer information; Communciations between March - June 2017

7 Big solar thermal plants; Company presentation GreenOneTec, 2017

8 Estimative offers from manufacturers and planers, 2017

9 Technology Data for Energy Plants; Energinet.dk, May 2012

10 f-EASY (SDH) (Simple calculator for a quick feasibility study of solar district heating). Available under: http://www.solarkey.dk/f-easy/f-easy.xlsx

Notes:

A According to Ref. 2, two plants exists with a size above 50 000 m² and both are located in Denmark. At the moment, the biggest solar thermal plant is Silkeborg (DK) with a size of approx. 157 000 m² and a capacity of 110 MWth, which was put into operation in December 2016. Note: Actually, in the city of Graz (A) plans are ongoing which intends to have much greater solar thermal plant (see "Big Solar Graz" with a planned collector area of approx. 500 000 m² and a seasonal storage (PTES) of approx. 1.8 million m³).

B Own calculations with SDH Online-Rechner with reference location Wuerzburg and feeding a DH grid (supply temperature 70 °C, return line 40 °C). Slightly increased efficiencies are assumed for the long term projection. The given lower value represents the location Stockholm and the upper value Barcelona.

C The presented efficiency is a result of calculations (yearly collector yield per annual global radiation; considered conditions see comment above). The lower and upper values represent Stockholm respectively Barcelona. Note: Collector yield and efficiency mostly depends on operation temperatures of the DH network, collector technology and several additional parameters (orientation, distance between collector rows, control strategy, heat exchanger, storage type, combination with other energy technologies, etc.). The efficiency is limited to approx. 65 % owing to physical reasons.

D Usually the needed electricity (solar pump, control, etc.) could be estimated with 0.7 - 1.2 kWh per 100 kWh heat production. Main part is the pumping energy which depends on collector type and field connection.

E Depends mainly on stagnation periods. Collectors without stagnation could have lifetimes above 30 years.

F Normally solar collectors are operated below 100 °C in order to reach "useful" collector yields. Reducing the temperature level leads to higher yield/efficiency. Note: Typical stagnation temperatures of FPCs are between 150 and above 200 °C.

G Reducing operation temperature of 1 K leads approx. 1 - 2 % higher solar output, as lower temperatures imply higher operating efficiency for the solar collectors.

H Most cost reduction potentials are seen in mounting system standardizations (e.g. fastening anchor, concrete elements, substructure) as big ground mounted solar thermal fields are relatively new (in comparison to solar thermal collectors itself) and learning effects would happen. The collectors itself would getting better regarding costs (production and prozess improvements) and efficiency (like actually developments in double glass / foil technologies).

I The given cost estimation is based on a 10 000 m² collector field plant including collectors, installation, piping, heat exchanger unit, diurnal storage (size 1 000 m³).

J Estimation for the whole solar thermal plant including mounting and piping. Surcharge for pile foundation for the substructure is considered. Nevertheless, soil condition is a big uncertainty in estimating the installation effort. Hint: A team of 4 - 5 people could install 200 - 300 m² collectors per day (including preparation and follow-up).

K Value is based on monitoring data. Key maintenance checks consist of: adaption and debugging control system, leakages (fluid loss and/or air in the system), fluid quality (PH value, glycol content), components (relief valves, expansion vessels, sensors, etc.) and landscaping. The time effort for visual inspection could be estimated as 16 hours (one day for 2 persons). Alternatively the whole maintenance could be estimated to EUR 1 - 2 per MWh. Data only valid for big solar thermal plants in megawatt scale.

L Except electricity no variable O&M costs occur.

M Formula is based on listed references and adjusted with given estimative offers. The formula could be used up to 50 000 m² (considered estimative offers range from 500 - 50 000 m² and for this range the formula fits).
N Given cost formula is converted from EUR/m² to EUR/kW_{th} with a conversion factor of 0.7 kW_{th}/m^2. x…Heat generation capacity
O From construction start on site to commissioning of a 10 000 m² plant.

4.4.2 Evacuated tube collectors

Evacuated tube collectors generally consist of two glass tubes, the inner tube being selectively coated. Heat losses are largely prevented by the vacuum. They have an additional heat-insulating effect due to the vacuum. Evacuated tube collectors with compound parabolic concentrator (ETC-CPC) uses additional mirror surfaces (integrated or external) increase the utilization rate. These so-called concentrating collectors achieve higher temperatures with the same absorber surface, since the specifically positioned curved mirrors cause more solar radiation to hit the same absorber surface. However, this advantage cannot be used with diffuse radiation since only directed beams can be concentrated.

Figure 21: CAPEX breakdown of solar thermal heating plants with evacuated tube collectors

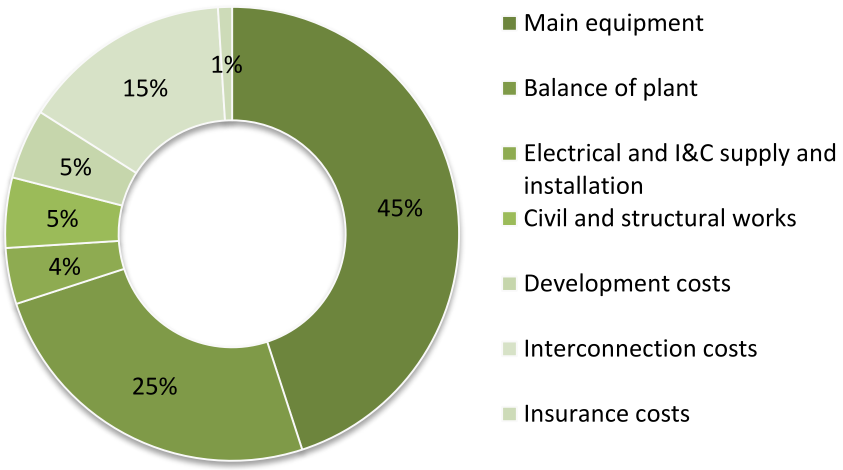


Table 13: Overview of solar thermal heating plants with evacuated tube collectors

	Unit	2015	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
A. Energy/technical data							**Lower**	**Upper**	**Lower**	**Upper**		
Collector area	m²	500 - 10 000									A	1, 2
Annual collector yield	MWh/(m².a)	0.408	0.409	0.410	0.411	0.412	0.372	0.700	0.374	0.710	B	3
Total efficiency, annual average	%	37.4	37.5	37.6	37.7	37.8	37	46	39	50	C	3
Electricity consumption	%/MWth	1	1	1	1	1	0.5	1.5	0.6	1.4	D	1, 4
Technical lifetime	years	25	25	25	25	25	20	30	20	30	E	1, 5
Steam supply		N/A	N/A	N/A	N/A	N/A					F	
Hot water		N/A	N/A	N/A	N/A	N/A						
Warm water		--	--	--	--	--	--	-	--	-		
Low temperature		(o)	(o)	(o)	(o)	(o)	o	+	o	+	G	
B. Environmental data												
CO2	g/MJ$_{th}$	0	0	0	0	0						
SO2	g/GJ$_{th}$	0	0	0	0	0						
NOX	g/GJ$_{th}$	0	0	0	0	0						
CH4	g/GJ$_{th}$	0	0	0	0	0						
N2O	g/GJ$_{th}$	0	0	0	0	0						
Particles	g/GJ$_{th}$	0	0	0	0	0						
C. Financial data												
Quality of CAPEX estimation		high										
Learning rate	%										H	
Nominal investment	M€/MW$_{th}$	0.75	0.70	0.65	0.60	0.56	0.60	0.80	0.45	0.65	I	1, 3, 5, 7
- of which equipment	M€/MW$_{th}$	0.45	0.42	0.39	0.36	0.33	0.35	0.53	0.28	0.41	J	1, 6, 7
- of which installation	M€/MW$_{th}$	0.30	0.28	0.26	0.24	0.22	0.17	0.35	0.14	0.28	K	1, 6, 7
Fixed O&M	k€/MW$_{th}$/a	3.5	3.3	3.0	2.5	2.0	2.8	4.5	1.6	3.0	L	1, 5, 7
Variable O&M excl. electricity costs	€/MWh$_{th}$	N/A	N/A	N/A	N/A	N/A					M	1, 5
X. Technology specific data												
Cost function (estimation)	€/m²	$C_{ETC\text{-}CPC}(A_{Coll})$ = 2 035 * (Collector Area)^(-0.15)									N	3, 6
Cost function (estimation)	M€/MW$_{th}$	Invest(x)=0.978$x^{-0.15}$									O	3, 6
Construction time	months	5	4	4	3	3	3	6	2	6	P	1, 5

References:

1 Ritter XL Solar GmbH (http://ritter-xl-solar.com/en/home/); Communications between March - May 2017
2 Ranking List of European Large Scale Solar Heating Plants; Solar District Heating (SDH), December 2016 (http://solar-district-heating.eu/ServicesTools/Plantdatabase.aspx)
3 SDH Online-Rechner (Online calculator for a quick feasibility study of solar district heating including seasonal storage); Solites (Steinbeis Forschungsinstitut für solare und zukunftsfähige thermische Energiesysteme), 2013 (http://www.sdh-online.solites.de/)
4 Solar district heating guidelines - Collection of fact sheets; SDH, August 2012 (http://solar-district-heating.eu/)
5 Manufacturer information; Communications between March - June 2017
6 Technology Data for Energy Plants; Energinet.dk, May 2012
7 Estimative offers from manufacturers and planers, 2017

Notes:

A According to Ref. 2, eight plants with in the range between 1 000 - 10 000 m^2 exists and most of them are located in Germany. At the moment, the biggest ETC plant is Senftenberg (DE) with a size of 8 300 m^2 and a capacity of 5.8 MW_{th}, which was put into operation in 2016.
B Own calculations with SDH Online-Rechner with reference location Wuerzburg and feeding a DH grid (supply temperature 70 °C, return line 40 °C). Slightly increased efficiencies are assumed for the long term projection. The given lower value represents the location Stockholm and the upper value Barcelona. Note: If the plant is operated only with water (no glykol) 1 - 2 % of the collector yield is needed for the active frost protection.
C The presented efficiency is a result of calculations (yearly collector yield per annual global radiation; considered conditions see comment above). The lower and upper values represent Stockholm respectively Barcelona. Note: Collector yield and efficiency mostly depends on operation temperatures of the DH network, collector technology and several additional parameters (orientation, distance between collector rows, control strategy, heat exchanger, storage type, combination with other energy technologies, etc.). The efficiency is limited to approx. 65 % owing to physical reasons.
D Electricity demand for solar pump and control is around 1 kWh per 100 kWh heat production. Variations for the solar pump could occur due to the hydraulic connection of the collector field.
E Depends mainly on stagnation periods. Collectors without stagnation could have lifetimes above 30 years.
F Technically ETCs could be used for high temperature applications till 140 °C and for some research activities they are operated till 180 °C (driving a Stirling engine). Hence, it is recommended to operate these collectors below 110 °C due to economic reasons. Temperatures above 110 °C requires higher installation efforts due to the "pressure equipment directive (2014/68/EU)" which lead to much higher installations costs and makes it uneconomical.
G Compared to FPC the ETC technology has a higher efficiency at higher collector temperatures. Nevertheless, in most SDH plants FPC have been chosen instead of ETC because of the lower price/performance ratio (Ref. 4).
H The price could be reduced to half if there were a corresponding market, but at the moment there is not a high demand for evacuated tube collectors. If the market does not change, no serious cost reductions are seen in the near future.
I The given cost estimation is based on a 10 000 m^2 collector field plant including collectors, installation, piping, heat exchanger unit, diurnal storage (size 1 000 m^3).
J In comparison to flat plate collectors, the equipment effort is a little bit lower and, going hand in hand, the installation a little bit higher. The reason for this is the lower standardization (especially in the mounting systems) which requires more on-site work.
K Estimation for the whole solar thermal plant including mounting and piping. Surcharge for pile foundation for the substructure is considered. Nevertheless, soil condition is a big uncertainty in estimating the installation effort. Hint: A team of 4 - 5 people could install 100 - 200 m^2 collectors per day (including preparation and follow-up).
L Yearly maintenance (e.g. adaption and debugging control system, leakages (fluid loss and/or air in the system), fluid quality (PH value, glycol content), components (relief valves, expansion vessels, sensors, etc.) and landscaping) is below 1 % of the investment costs and could be done within running operation (effort for 10 000 m^2: 2 persons x 8 h per year). In comparison to FPCs, this technology has slightly higher O&M costs, due to higher efforts like checking the collectors (each collector pipe and their suitable connection), visual inspection, exchange of small parts, filter and sealing changes, etc.
M Except electricity no variable O&M costs occur.
N Formula is based on listed references and adjusted with given estimative offers. The formula could be used up to 50 000 m^2 (considered estimative offers range from 500 - 50 000 m^2 and for this range the formula fits).
O Given cost formula is converted from EUR/m^2 in EUR/kW_{th} with a conversion factor of 0.7 kW_{th}/m^2. x…Heat generation capacity

P	In comparison to flat plate collectors this type consumes a little bit longer construction time as there exists not so much standardized collector solutions.

5 Heating/ Cooling – Heat Pumps

District heating networks are an interesting application field for large heat pumps. While some heat pumps are already used in Scandinavian networks, there are only a few plants in the rest of Europe. However, the interest of heat grid operators in large heat pumps is increasing.

Large-scale heat pumps, according to the state of the art, currently reach supply heating temperatures of around 80 °C. For the integration into district heating networks, this maximum supply temperature is in many cases too low. In the winter months the supply temperatures in district heating systems are often above 100 °C, so that the operation of large heat pumps seems not appropriate.

If the flow temperature of the heat pump is not sufficient, there is the possibility of post-heating with auxiliary (mostly boiler) systems. If the return line of the district heating system is used as the heat source for the heat pump, the cooling of the return flow can have a positive effect on the fuel utilization rate during the operation of a cogeneration system.

Another potential application field is the improved utilization of existing heat storages (especially seasonal storages). Large heat pumps can be used to further reduce the temperatures in the heat storage, which means that the stored heat is used more effectively. In addition, there is a favourable temperature level for the operation of large heat pumps, as these are generally used in the basic load in order to achieve the most economical operation with high full utilization hours. Large heat pumps are therefore often operated in combination with CHP plants and boilers to cover the peak load. In addition to pure heat generation, heat pumps can also be used to increase the capacity of existing district heating systems.

5.1 Electric heat pumps

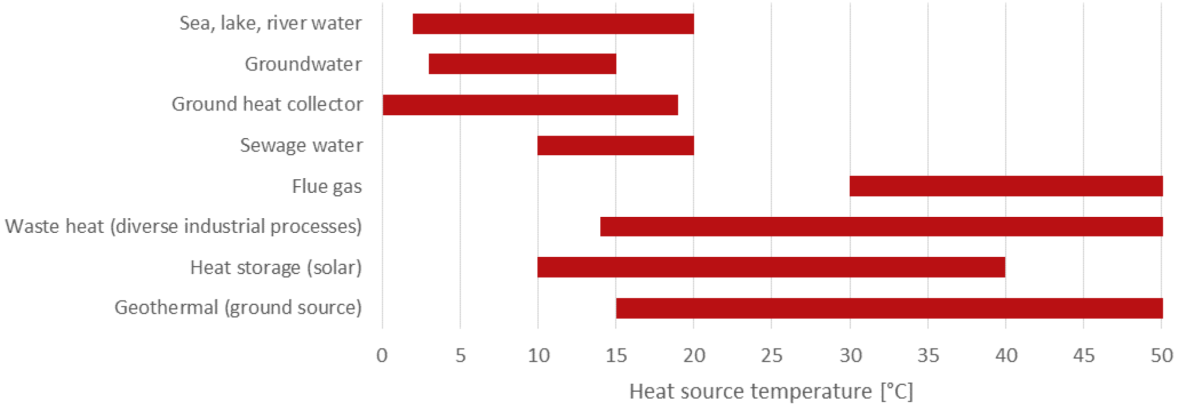
Electric heat pumps could be used in wide applications and very different heat sources. That is why, a general approach is introduced in order to estimate the COP (Coefficient Of Performance) based on the temperature levels (source, sink) and a overview of the cost compositions.

The performance depends strongly on the lower and upper temperature level. The theoretically maximum achievable performance coefficient “COPmax” of a heat pump is limited by the reciprocal of the Carnot efficiency. For calculations the absolute temperature values must be used. The efficiency of a heat pump (ηHP) is formed from the ratio of actual performance (COP) to ideal performance (COPmax) at the used temperature levels. Practically heat pumps achieve efficiencies in the range 0.45 to 0.55. For the COP calculation an efficiency of 0.5 could be used.

$$COP_{max} = \frac{1}{\eta_C} = \frac{T_{warm}}{T_{warm} - T_{cold}} \Longrightarrow \eta_{HP} = \frac{COP}{COP_{max}} \rightarrow COP = COP_{max} * \eta_{HP}$$

Based on the figure below, the heat source temperatures could be estimated for the efficiency calculation. The visualization is limited to 50 °C as the temperature level of flue gas, waste heat and geothermal over and above that. The source “ambient temperature” is not listed, because this heat source is not used for district heating applications due to low COPs. As a rough estimation, the local average ambient temperature could be used for surface water (e.g. seas, lakes).

Figure 22: Typical heat source temperatures of heat pumps in DH systems



Source: Large heat pumps in European district heating systems; A. David, 2016

The CAPEX breakdown structures below are based on three different heat sources. In general, the heat pump causes about 50 percent of the total investment. Heat source exploitation consumes approx. 20 %, electrical and civil and structural works both approx. 10 %. The development and interconnection costs amount to approx. 5 % each of the total investment (Ref. 4). Based on these figures and on the financial data of the provided table the costs for different applications could be estimated.

Figure 23: CAPEX breakdown of electrical heat pumps with ground water source

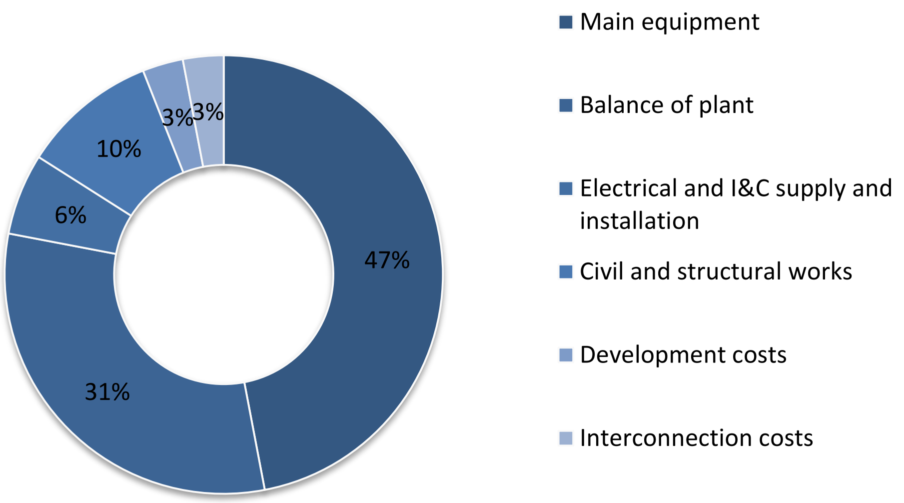


Figure 24: CAPEX breakdown of electrical heat pumps with waste heat source

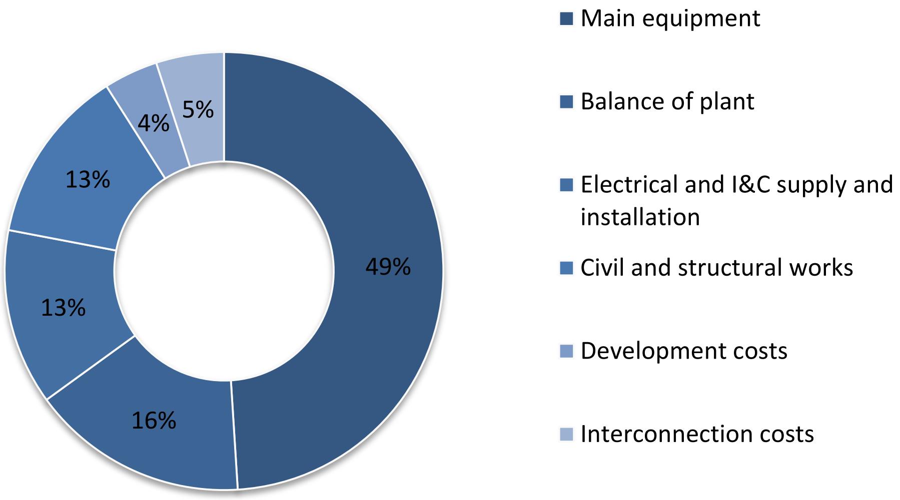


Figure 25: CAPEX breakdown of electrical heat pumps with flue gas source

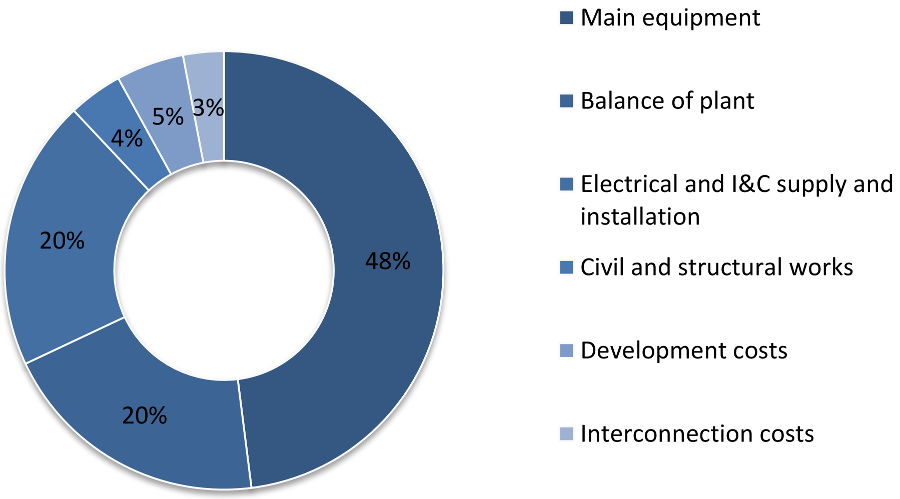


Table 14: Overview of electric driven heat pumps

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Thermal power output	MW_{th}	1 - 10						0.5	20	0.5	40		A	1, 2, 3
Cooling generation capacity	MW_{th}	0.7 - 7						0.35	15	0.35	30		B	1, 2, 3
COP Heating	%	350	360	370	380	410		330	380	350	450		C	1, 4, 5, 6
COP Cooling	%	250	260	270	280	310		230	280	250	350		D	7
Electricity consumption	%/MW_{th}	10	9	7	5	4		4	10	3	6		E	1
Technical lifetime	years	20	20	25	25	25		15	30	15	30		F	1, 8
Steam supply		N/A	N/A	N/A	N/A	N/A							G	3, 4, 6
Hot water		N/A	N/A	N/A	N/A	N/A								
Warm water		--	--	--	--	--		--	-	--	-		H	
Low temperature		(o)	(o)	(o)	(o)	(o)		o	(+)	o	+		I	
B. Environmental data														
CO2	g/MJ_{th}	0	0	0	0	0								1
SO2	g/GJ_{th}	0	0	0	0	0								
NOX	g/GJ_{th}	0	0	0	0	0								
CH4	g/GJ_{th}	0	0	0	0	0								
N2O	g/GJ_{th}	0	0	0	0	0								
Particles	g/GJ_{th}	0	0	0	0	0								
C. Financial data														
Quality of CAPEX estimation		high												
Learning rate	%												J	9
Nominal investment	M€/MW_{th}	0.72	0.66	0.60	0.56	0.54		0.5	1.0	0.4	0.8		K	1, 2, 9, 10, 11
- of which equipment	M€/MW_{th}	0.36	0.33	0.3	0.28	0.27		0.26	0.4	0.22	0.32		L	1, 5
- of which installation	M€/MW_{th}	0.36	0.33	0.3	0.28	0.27		0.26	0.4	0.22	0.32			1, 5
Fixed O&M	k€/MW_{th}/a	3.0	3.0	2.7	2.4	2.0		2.0	4.0	1.0	3.0			1, 12
Variable O&M excl. electricity costs	€/MWh_{th}	2.0	1.8	1.7	1.6	1.6		1.5	2.0	1.5	2.0		M	1
X. Technology specific data														
Cost function (estimation)	M€/MW_{th}	$C_{elHP}(Q_{\cdot th}) = 0.352 * Q_{\cdot th}^{-0.122}$											N	
Construction time	months	6	6	6	6	6		4	9	4	9		O	1
Space requirement	m²/MW_{th}	20	20	20	20	20		10	40	10	40		P	11
Primary regulation	%/30sec	10	10	10	10	10		10	25	10	30		R	1
Secondary regulation	%/min	20	20	20	20	20		20	40	20	40			1
Minimum load	%	20	20	15	15	10		10	30	10	30			1, 11
Warm start-up time	h	0	0	0	0	0		0	1	0	1			1, 11
Cold start-up time	h	0.5	0.5	0.5	0.5	0.5		0.25	2	0.2	1.50			1, 11

References:

1. Technology Data for Energy Plants; Energinet.dk, August 2016
2. Best available technologies for the heat and cooling market in the European Union; EC-JRC, 2012
3. Analyse des Potenzials von Industriewärmepumpen in Deutschland; Universität Stuttgart IER/IZW, December 2014 (online available: http://www.ier.uni-stuttgart.de/publikationen/veroeffentlichungen/forschungsberichte/downloads/141216_Abschlussbericht_FKZ_0327514A.pdf)
4. Renewables for Heating and Cooling - Untapped Potential; OECD/IEA, 2007
5. Store varmepumper i fjernvarmeforsyningen - Evaluering af initiativerne for rejsehold og tilskudsordning for store varmepumper i fjernvarmeforsyningen; Energistyrelsens, May 2016
6. Large heat pumps in European district heating systems; Andrei David, Presentation at "En+Eff - 22nd International Trade Fair and Congress" on 20th April 2016, Frankfurt
7. Wärmepumpe - Lecture Notes (W10 Physikalisches Grundpraktikum, Abteilung Wärmelehre); TU Dresden, May 2015
8. Economic efficiency of building installations - Fundamentals and economic calculation; VDI Guidelines, September 2012
9. Klimaneutraler Gebäudebestand 2050; Umweltbundesamt, 2016; Online available: http://www.umweltbundesamt.de/publikationen/klimaneutraler-gebaeudebestand-2050
10. Heat Pumps - Technology Brief; IEA-ETSAP and IRENA, January 2013
11. Manufacturer information; Input from autumn 2015
12. District Heating; IEA-ETSAP and IRENA, January 2013

Notes:

A Ref. 3 provides an overview which includes heat output, available supply temperature and refrigerant of 44 industrial heat pumps (which also mostly suits for DH applications) of 14 manufacturers. The performance spectrum of the offered heat pumps ranges from 0.015 to 20 MW. By parallel operation larger heating capacities can also be achieved.

B Calculated based on the heating capacity and an average COP Cooling of 250 %.

C The given values are calculated for a supply temperature of 80 °C and a source temperature of 30 °C. Increasing the COPs will primarily be caused through lower supply temperatures in the future.

D COP Cooling = COP Heating - Pel.

E Contains only auxiliary electricity (pumps etc.) but not the driving power (which depends on the COP and is characterized through the temperature levels (source, sink); Pel = Q.th / COP). The electrical auxiliary power consumption is not included in the COP estimation/calculation.

F The technology itself is very reliable and robust and with regular maintenance, 25 years of use is no problem. There are some specimens that have been in operation for more than 40 years. Due to legal regulations (F-Gas regulation), the refrigerants were substituted with less GWP (global warming potential) in some old machines. But it could be that the "new" refrigerants could harm to the heat pumps, as no long term experiences exists.

G The technology is mostly predestined for lower temperature applications. Nevertheless, R&D projects are ongoing to reach supply temperatures up to 160 °C (therefore, also new refrigerants are investigated). E.g. http://dry-f.eu/

H Only few manufacturers offers heat pumps with supply temperatures up to 100 °C (Ref. 3). The few existing heat pumps are mostly used for industrial purposes.

I Most heat pump applications in DH systems work with temperature levels up to 70 - 80 °C (Ref. 12).

J No high scientifically resilient figures are available. According to Ref. 9, a learning rate of 5 % for material and the same for the work is assumed. But this figures are just estimations and mostly based on small-scale heat pumps. Higher learning rates could be expected for large-scale heat pumps.

K Given CAPEX estimation (2015-2050) is based on a 1 MW_{th} heat pump. Although the CAPEX estimation is set "high", the lower and upper CAPEX figures show a bigger bandwith. The reason for this is, that only very few manufacturers dominate the large-scale market for heat pumps. But there are a lot of other heat pump manufacturers which would like to have higher market shares, whereby they offer their products at lower price levels. That means, chosing the manufacturer has a very high influence on the heat pump price.

L On average, Ref. 5 shows that the heat pump itself constitutes approx. 50 % of the total investment.

M Part load operation could increase variable O&M costs.

N Cost function only valid for the heat pumps itself in order to easily compare different heat sources. Normally the heat pump itself consumes approx. 50 % of total investment costs (see also the CAPEX breakdown structures for different heat sources). The function is based on reference project information and manufacturer estimative offers.

O Depends on future production figures, plant standardizations and of course on-site conditions. Large heat pumps could have long delivery times up to 1 year.

P Approximately 50 % is for the heat pump and the other half for other installations (e.g. interconnection, maintenance spare, etc.).

R The future regulation service markets will have a big influence on regulation ability improvements (e.g. power-to-heat applications).

5.2 Gas driven heat pumps

Gas driven heat pumps use a gas engine (e.g. Otto engine) to drive the heat pump compressor. The waste heat from the engine is additionally used, so that a various combination of CHPs, heat pump, condensing value utilization and primary energy is used. In principle, all gas engine heat pump technologies are reversible and can both used for heating and cooling/air conditioning. Hence, not all products on the market may be designed for cooling also. A special feature of the gas engine heat pump is the offering of four different temperature levels:

- evaporator heat: 10 °C and lower, depending on the heat source
- condenser heat: 40 - 50 °C from the heat pump process
- cooling water waste heat: approx. 65 °C of the gas engine
- sensitive heat: approx. 100 - 600 °C from the exhaust gas of the gas engine

Big advantage of gas heat pumps are that they less rely on free renewable heat sources, compared to electrical heat pumps. Furthermore, their capacity is less depending on the heat source temperature which results to a more constant heat delivery profile. One of the biggest disadvantage is, that this technology can only be installed where gas is available. As they direct compete to heat only boilers not so much systems are existing yet. Applications mainly exist for commercial buildings but not for DH systems.

Figure 26: CAPEX breakdown of gas driven heat pumps

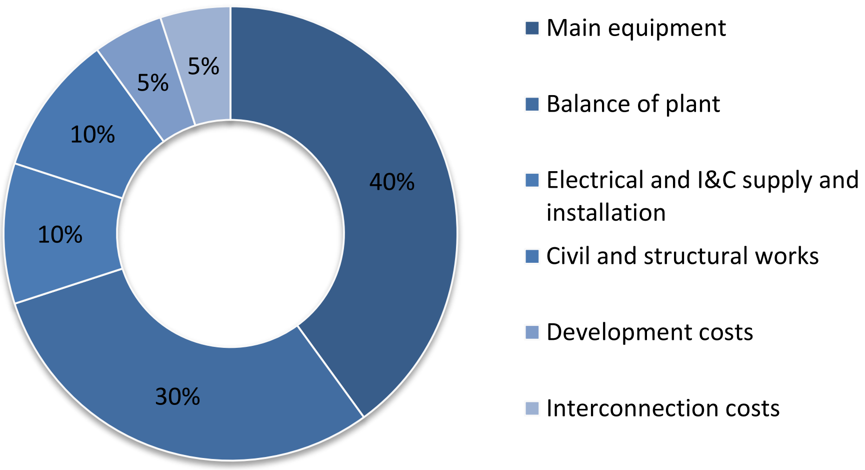


Table 15: Overview of gas driven heat pumps

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Heat generation capacity	MW_{th}	0.025 - 0.85						0.02	1.2	0.02	2.0		A	1, 2, 3
Cooling generation capacity	MW_{th}	0.025 - 0.70						0.02	0.85	0.02	1.5			1, 2
Heating factor	%	155	155	157	158	160		110	170	120	170		B	1, 2, 3
Refrigeration factor	%	145	145	147	58	160		100	160	110	160			1, 4
Heating, annual efficiency	%	120	125	130	135	140		115	135	120	150		C	3, 4, 5
Cooling, annual efficiency	%	100	105	110	115	120		90	120	110	130		D	4
Electricity consumption	%/MWth	1.2	1.2	1.1	1.1	1		1.0	1.5	1.0	1.5			3, 6
Technical lifetime	years	15	20	20	20	20		15	20	15	20		E	2, 5, 7
Steam supply		N/A	N/A	N/A	N/A	N/A								
Hot water		N/A	N/A	N/A	N/A	N/A								
Warm water		--	--	--	--	--		--	-	--	-			
Low temperature		(o)	(o)	(o)	(o)	(o)		o	(+)	o	+			
B. Environmental data														
CO2	g/MJ_{th}	18	18	18	18	18							F	8
SO2	g/GJ_{th}	<	<	<	<	<								
NOX	g/GJ_{th}	13	13	13	13	13								2
CH4	g/GJ_{th}	<	<	<	<	<								
N2O	g/GJ_{th}	<	<	<	<	<								
Particles	g/GJ_{th}	<	<	<	<	<								
C. Financial data														
Quality of CAPEX estimation		low												
Learning rate	%													
Nominal investment	$M€/MW_{th}$	1.3	1.2	1.1	1.0	0.9		1.0	1.6	0.8	1.3			2, 4, 9
- of which equipment	$M€/MW_{th}$	0.65	0.60	0.55	0.50	0.45		0.48	0.72	0.36	0.54			2
- of which installation	$M€/MW_{th}$	0.65	0.60	0.55	0	0.45		0.48	0.72	0.36	0.54			2
Fixed O&M	$k€/MW_{th}/a$	4.7	4.7	4.7	4.7	4.7							G	2, 9
Variable O&M excl. electricity costs	$€/MWh_{th}$	2	2	2	2	2								10
X. Technology specific data														

References:

1 Marktübersicht Gaswärmepumpen 2013/14 Gasklimageräte, Gasmotorwärmepumpen, Gasabsorptionswärmepumpen, Gasabsorptionskälteanlagen, Gasadsorptionswärmepumpen: Angebot und Anbieter; ASUE, 2013
2 Technology Data for Individual Heating Plants and Energy Transport (Updated chapters); Danish Energy Agency and Energinet.dk, August 2016
3 BHKW-Kenndaten; ASUE, 2014
4 Gas Heat Pumps - Efficient heating and cooling with natural gas; GasTerra, 2010
5 BWP-Branchenstudie 2013 - Szenarien und politische Handlungsempfehlungen - BWP, 2013
6 Heizen und Kühlen mit Gaswärmepumpen / Gasklimageräten; ASUE, 2008
7 WAS KOSTET DIE ENERGIEWENDE? Wege zur Transformation des deutschen Energiesystems bis 2050; Fraunhofer ISE, 2015
8 Gaswärmepumpen; ASUE, 2002
9 Klimaneutraler Gebäudebestand 2050; Umweltbundesamt, 2016; Online available: http://www.umweltbundesamt.de/publikationen/klimaneutraler-gebaeudebestand-2050
10 Heizen, Kühlen und Klimatisieren mit Erdgas (Tagungsband der ASUE-Fachtung); ASUE, June 2016

Notes:

A The power output could be controlled in a range between 35 - 100 % by modulating the gas burners.
B Depending on model and application (heating temperature), the nominal efficiency can vary between around 1.2 and 1.6 NCV.
C Application: Ground heat to 60 - 70 °C supply temperature.
D Application: Cooling 6/12 °C.
E The technical life time of gas heat pumps is at least fifteen years if maintained according to manufacturer regulations (Ref. 6).
F The emissions are calculated from fuel to thermal output, whereas the gas engine contributes with 50 % of 155 % heating factor (that means conversion factor of 50/155 from fuel to thermal output).
G Maintenance on the gas engine is initially limited to an annual visual inspection. The engine oil, spark plugs and V-belt must be replaced every 10 000 operating hours. It takes approximately half a working day to inspect a standard installation. Every 30 000 operating hours the system requires an overhaul, during which components in the periphery of the engine are replaced as a precautionary measure. The revolving part of the engine remains unaltered. The compressors (usually scroll compressors) are entirely maintenance-free (Ref. 7).

5.3 Absorption heat pumps

Thermally driven heat pumps use the same thermodynamic cycle as electrically driven compression heat pumps, however the compressor is replaced by a thermal sorption cycle. To drive the cycle thermal energy is needed. Electricity is only needed for auxiliary components like pumps to circulate the working fluid. Thermally driven machines are often used for cooling purposes in combination with waste heat or heat produced by renewable sources. Nevertheless, they can also work as heat pumps.

In general the cycles are based on a working pair of a refrigerant and a sorption medium. In absorption devices the refrigerant is absorbed, i.e. dissolved, in the liquid sorption medium changing its concentration. Most common working pairs are Water/Lithium Bromide and Ammonia/Water.

In order to increase performance configurations such as double-effect machines have been developed. Such configurations are thermodynamically more efficient but need higher driving temperatures and usually require complex hydraulics and sophisticated control. Therefore, they are less frequent than single-effect machines. Sources could be hot water, steam or even directly fired. These machines are more expensive than the single-effect machines.

Absorption machines offer quite stable COPs both in cooling/heat pumping mode. These devices face problems such as crystallization of the sorbent and corrosion and efficiency losses from the circulation pumps. Ammonia/water machines require adapted pumps.

The following table summarizes the technologies, the working pairs used and compare the main properties and performance of thermally driven heat pumps.

Ammonia/Water: Are based on ammonia as a refrigerant and water as a solvent. They can also reach very low evaporator temperatures (e.g. -50 °C).

Water/Lithium bromide: The evaporator temperature cannot be below approx. 3 °C, since water is used as a refrigerant. However, this limitation is not a problem if, for example, waste heat is to be used as a heat source at a not too low temperature level.

Table 16: Technology overview

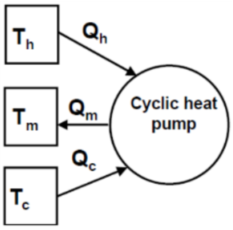
Refrigerant/sorbent	Water/LiBr	Water/LiBr	Ammonia/Water
Temperature Heat Source [°C]	75 – 110	135 – 200	100 - 180
Capacity [kW]	15 – 12 000	200 – 6 000	18 - 700
COP Heating	1.4 – 1.7	1.8 – 2.2	1.4 – 1.7
COP Cooling	0.6 – 0.7	0.9 – 1.3	0.5 – 0.7

Source: IEA HPP Annex 34: Thermisch angetriebene Wärmepumpen zum Heizen und Kühlen, I. Malenković, 2012

For reversible operation (both heating and cooling) mostly Water/LiBr machines are in usage, beside temperatures below 0 °C are required, Ammonia/Water machines will be used.

For designing absorption heat pumps and temperature level estimations it has to be considered, that the “lower” temperature ratio (T_m-T_c) has to be less than the “higher” (T_h-T_m). Using the heat pump as a chiller, low driving temperatures (< 80 °C) should be avoided as the efficiency and capacities are getting smaller.

Figure 27: Technology principle of absorption heat pumps



Source: IEA HPP Annex 34: Thermisch angetriebene Wärmepumpen zum Heizen und Kühlen, I. Malenković, 2012

The CAPEX breakdown structure below is based on a single-effect machine with 1 MW_{th} output for heating usage. The position "Main equipment" considers also transport costs for shipping etc. as the manufacturers of such machines are mostly located in Asia and North America.

Figure 28: CAPEX breakdown of absorption driven heat pumps (single-effect)

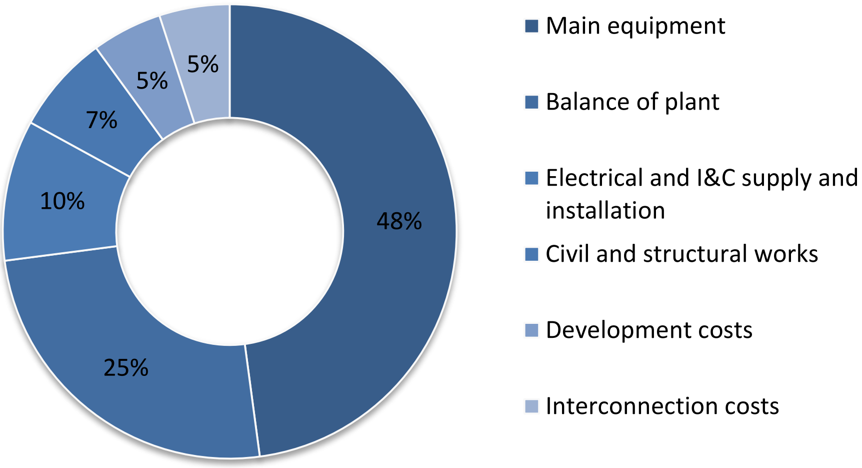


Table 17: Overview of absorption driven heat pumps (single-effect)

	Unit	2015	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
A. Energy/technical data							**Lower**	**Upper**	**Lower**	**Upper**		
Thermal power output	MW_{th}	0.15 - 12										1
Cooling generation capacity	MW_{th}	0.1 - 10										1
COP Heating	%	170	170	171	172	173	140	170	140	175	A	2, 3, 4
COP Cooling	%	70	70	71	72	73	40	70	40	75	B	2, 3, 4
Electricity consumption	%/MWth	1.5	1.5	1.5	1.5	1.5	1	3	1	3		2, 5
Technical lifetime	years	25	25	25	25	25	20	30	20	>30		2, 5
Steam supply		N/A	N/A	N/A	N/A	N/A					C	1, 4
Hot water		N/A	N/A	N/A	N/A	N/A						
Warm water		--	--	--	--	--	--	-	--	-	D	
Low temperature		(o)	(o)	(o)	(o)	(o)	o	(+)	o	+		
B. Environmental data												
CO2	g/MJ_{th}	0	0	0	0	0						5
SO2	g/GJ_{th}	0	0	0	0	0						
NOX	g/GJ_{th}	0	0	0	0	0						
CH4	g/GJ_{th}	0	0	0	0	0						
N2O	g/GJ_{th}	0	0	0	0	0						
Particles	g/GJ_{th}	0	0	0	0	0						
C. Financial data												
Quality of CAPEX estimation		medium										
Learning rate	%	7 - 8									E	5
Nominal investment	$M€/MW_{th}$	0.42	0.39	0.38	0.37	0.35	0.30	0.60	0.25	0.50	F	2, 6, 7
- of which equipment	$M€/MW_{th}$	0.21	0.195	0.19	0.185	0.175	0.15	0.24	0.14	0.21	G	5, 6
- of which installation	$M€/MW_{th}$	0.21	0.195	0.19	0.185	0.175	0.15	0.24	0.14	0.21		5, 6
Fixed O&M	$k€/MW_{th}/a$	2	2	2	2	2	1	3	1	3		5
Variable O&M excl. electricity costs	$€/MWh_{th}$	0.30	0.28	0.25	0.24	0.23	0.30	0.40	0.20	0.30		5
X. Technology specific data												
Cost function (estimation)	$M€/MW_{th}$	$C_{\text{Ab-HP, single-effect}}(Q_{\cdot th}) = 0.42 * Q_{\cdot th}^{-0.205}$									H	8
Cost function (estimation)	$M€/MW_{th}$	$C_{\text{Ab-HP, double-effect}}(Q_{\cdot th}) = 0.66 * Q_{\cdot th}^{-0.205}$									I	8
Construction time	months	6	6	6	6	6	4	9	4	9		5
Minimum load	%	10	10	10	10	10	10	10	10	10	J	5
Warm start-up time	h	0	0	0	0	0	0	1	0	1		5
Cold start-up time	h	0.5	0.5	0.5	0.5	0.5	0.25	2	0.25	2		5

References:

1 Thermally driven heat pumps; IEA HPP Annex 34, 2013
2 Information of manufacturers; Communications between March - May 2017
3 Solar Energy; Christoph Richter, Daniel Lincot and Christian A. Gueymard, 2013 (© Springer Science+Business Media New York)
4 Absorption Chillers and Heat Pumps; Keith E. Herold, Reinhard Radermacher and Sanford A. Klein, 1996 (© Taylor & Francis Group, LLC)
5 Technology Data for Energy Plants; Energinet.dk, August 2016
6 Best available technologies for the heat and cooling market in the European Union; EC-JRC, 2012
7 S.O.L.I.D. Gesellschaft für Solarinstallation und Design mbH (http://www.solid.at/en/)
8 PREISATLAS - Ableitung von Kostenfunktionen für Komponenten der rationellen Energienutzung; Lucas et al., 2002

Notes:

A Based on a single-effect absorption machine typical COPs are between 1.4 - 1.7 (depending on temperature differeneces and on the working pairs). Due to thermodynamic / physical principles the COP is restricted to 1.8. See also: "Zero - Order Model".
B COP cooling = COP Heating - 100%. See also: "Zero - Order Model".
C Absorption heat pumps are not predestined for high supply temperature usage.
D The reachable temperatures for heating usage is limited through the crystallization line, which depends on vapour pressure and mass fraction of the media. E.g.: A single-effect machine could provide up to 80 °C for heating usage, based on 160 °C hot water source and 30 °C chilled water (Ref. 2).
E Estimation based on Ref. 5 in which it is assumed that the costs are decreasing by 7 - 8 % for every doubling.
F Given CAPEX estimation (2015-2050) is based on a 1 MW_{th} heat pump. For other thermal power ranges the given cost function could be used.
G Relation depends very much on-site conditions (e.g. specific type, availability of heat source, etc.).
H Formula is based on given reference and adjusted with estimative offers. The formula could be used in a range of 1 - 10 MW_{th}.
I Formula is based on given reference and formula used above. Note: The comparison of ref. 8 comes up with a factor of 1.58 higher costs for double than single-effect machines.
J Percent of full load operation.

6 Combined heat and power

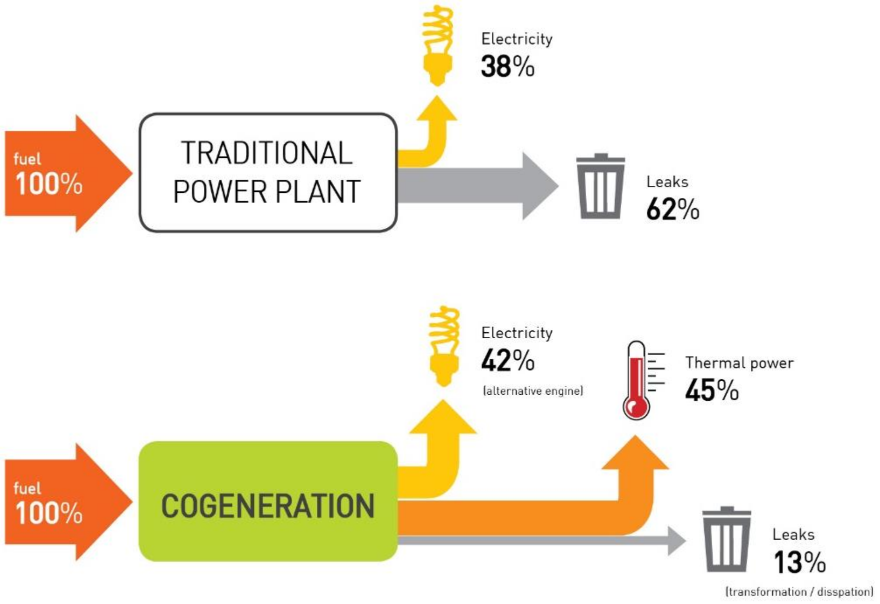
Combined heat and power (CHP), also known as cogeneration, is:

- **The concurrent production** of electricity or mechanical power and useful thermal energy (heating and/or cooling) from a single source of energy.
- **A suite of technologies** that can use a variety of fuels to generate electricity or power at the point of use, allowing the heat that would normally be lost in the power generation process to be recovered to provide needed heating and/or cooling.

CHP technology can be deployed quickly, in some cases cost-effectively, and with few geographic limitations. CHP can use a variety of fuels, both fossil- and renewable-based. It has been employed for many years, mostly in industrial, large commercial and institutional applications. CHP can provide highly efficient electricity and process heat (see also comparison of the figure below) to some of the most vital industries, largest employers, urban centres, etc. It is reasonable to expect CHP applications to operate at high total degrees of fuel utilization.

On a large scale, conventional steam generators and combined cycle power plants are used and at smaller scales (typically below 1 MW) gas- or diesel engines may be used.

Figure 29: Comparison of "conventional" electricity production to CHP application



Source: https://imagemag.ru/img-ba_cogeneration.html

6.1 Combustion technologies

General clarifications

Data in tables below have been found after research of different sources / references / in-house data as indicated in literature list and with help of thermodynamic simulation using "EBSILON®Professional". Literature and used references for this chapter are indicated within chapter 6.1.8.

Individual remarks for parameters provided below

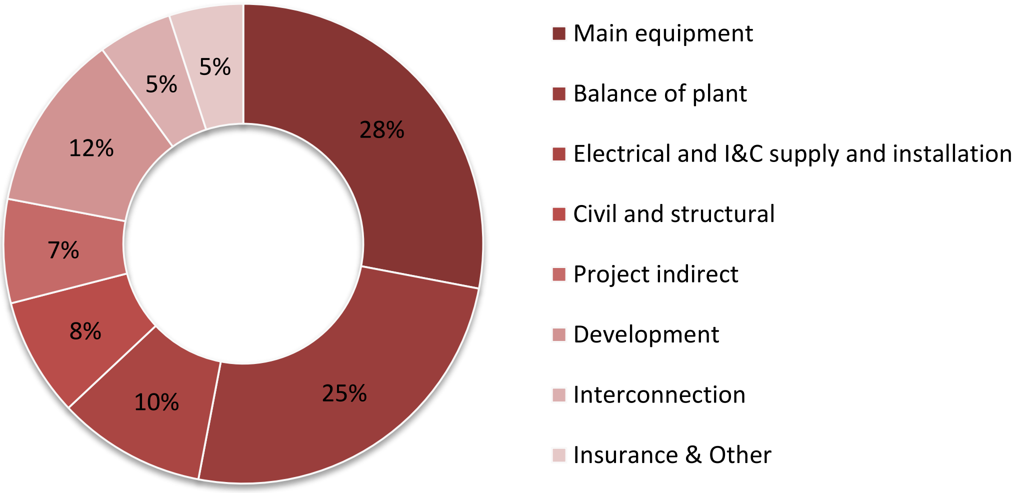
- The general approach for the calculation of thermal power exchange from the combined heat and power plant (CHPP) to the district heating system is the 105 °C level for the district heating temperature. Additionally the corresponding electrical power of the individual CHPP is taken for further considerations (simultaneous "heat and power mode").
- Heat generation capacity: The range of thermal power that can be produced by CHPPs of presented configuration
- Electrical power generation: The range of electrical power that can be produced by CHPPs of presented configuration
- Net electrical efficiency: Electrical net efficiency of the CHPP running in "heat and power mode"
- Degree of fuel utilization accountable to el. Power: Electrical power divided by sum of electrical and thermal power.
- Degree of fuel utilization accountable to district heating: Thermal power divided by sum of electrical and thermal power.
- Total degree of utilization, nominal load: Sum of electrical and thermal power divided by fuel heat
- Total degree of utilization, annual average: As factor above, but based on planned availability of the CHPP per year
- Electricity consumption: Electrical auxiliary power per produced thermal power (in "heat and power mode").
- Technical lifetime: Estimated lifetime of a new "greenfield" CHPP with presented configuration
- Table: Steam supply, Hot water, Warm water, Low temperature: For corresponding factors "Cb" (electric power divided by thermal power in "heat and power mode") and "Cv" (electric power in "heat and power mode" divided by maximum electric power in "only electric power mode" – using a condensing steam turbine with steam extraction) please see "Notes" below for the individual tables.
- Environmental Data: Emissions produced per thermal power produced (in "heat and power mode" i.a.)
- Financial Data: "Medium" quality is chosen, since estimations are based on data as indicated in literature list. Financial data is not based on binding offers from EPC (Engineering, Procurement and Construction) contractors or OEMs (Original Equipment Manufacturer).
- All financial data are given per electrical power produced (maximum electric power in "only electric power mode" – using a condensing steam turbine with steam extraction).
- Uncertainty: Uncertainty gives an estimated error range, considering capacity range, assumption influence and calculation uncertainty.

6.1.1 Subcritical steam generators (approx. > 20 MW thermal output)

For CHPPs using backpressure steam turbines, the approach for the calculation of thermal power that can be used for district heating is, as stated above, 105 °C for the district heating temperature ("Warm water") and a minimum of 10 °C spread of the backpressure steam temperature of the steam turbine (115 °C saturated at 1.7 bar). The corresponding electrical power, when running the plant in this backpressure mode, is used for the calculation of further parameters of the tables below. Maximum electrical power (see also Cv factor) of such a CHPP using a condensing steam turbine with steam extraction can be produced in "condensing mode"; that means without any thermal heat production for district heating.

The CAPEX breakdown structure of this category is listed in the figure below.

Figure 30: CAPEX breakdown of subcritical steam generators[4]



6.1.1.1 Natural gas fired fired subcritical steam generators

In natural gas fired fired subcritical steam generators, natural gas is burnt in a furnace section. Heat from the combustion and the exhaust gas is used to produce subcritical steam from feed water. Steam is expanded in backpressure (1.7 bar) steam turbine for electricity production. Heat from backpressure steam or extracted steam is used via condensation for district heating. The alternative design is that heat is taken from steam turbine extraction at proper pressure level.

Future prospects for parameters are mainly based on a possible further (small) development on steam turbines' efficiencies and a reduction of auxiliary power. Combustion efficiency of gas is estimated as constant.

Assumptions for the data in the table below: Natural gas (LHV appr. 40 MJ/kg) fired subcritical steam generator (combustion eff. approx. 95%; 3% O_2 flue gas; steam 120 bar, 500 °C) with backpressure steam turbine (performance values reclined on Siemens SST-400 class).

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[4] Cost for the district heating connection itself (like net pumps and other auxiliary units) will be in the range of 1%

Table 18: Overview of natural gas fired subcritical steam generators

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2, 4
Heat generation capacity	MW$_{th}$	20 - 250												
Electrical power generation	MW$_{el}$	10 - 100												
Net electrical efficiency	%	26	26	27	27	28		25	28	29	31			
degree of fuel utilization accountable to el. Power	%	28	28	29	29	30		27	29	28	31		A	
degree of fuel utilization accountable to district heating	%	72	72	71	71	70		71	73	69	71		B	
Total degree of utilization, nominal load	%	95	95	95	95	95		90	96	92	97			
Total degree of utilization, annual average	%	87	87	87	87	87							C, D	
Electricity consumption	%	0.9	0.9	0.85	0.85	0.8		0.8	1.2	0.7	1		E	
Technical lifetime	years	25	25	30	>30	>30		25	30	25	35			
Steam supply		+	+	+	+	+		o	++	o	++		F	
Hot water		o	o	o	o	o		o	+	o	+		G	
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	o	(o)	o		H	
Low temperature		-	-	-	-	-		-	o	-	o		I	
B. Environmental data														5, 6, 7
CO2	g/MJ$_{th}$	110	110	110	110	110		100	120	100	120			
SO2	g/GJ$_{th}$	<	<	<	<	<								
NOX	g/GJ$_{th}$	65	65	60	60	50		60	70	45	55			
CH4	g/GJ$_{th}$	<	<	<	<	<								
N2O	g/GJ$_{th}$	<	<	<	<	<								
Particles	g/GJ$_{th}$	<	<	<	<	<								
C. Financial data													J	1, 3, 8, 9
Quality of estimation		medium												
Nominal investment	M€/MW$_{el,max}$	1.72	1.72	1.63	1.63	1.45		1.45	2.17	1.45	2.17		K, L	
- of which equipment	M€/MW$_{el,max}$	1.18	1.18	1.09	1.09	1.00		1.00	1.45	1.00	1.45			
- of which installation	M€/MW$_{el,max}$	0.54	0.54	0.54	0.54	0.45		0.45	0.72	0.45	0.72			
Fixed O&M	k€/MW$_{el,max}$/a	9	9	9	9	7		5	14	5	14			
Variable O&M excl. electricity costs	€/MWh$_{el,max}$	0.5	0.5	0.5	0.5	0.5		0.3	1	0.3	1			
X. Technology specific data														
Cost function (estimation)	M€/MW$_{el}$	Invest(x)=4.59x$^{-0.20}$											M	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for steam turbine SST-400
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich‟, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013

Notes:

A =Pel/(Pel+Pth) in "heat and power mode"
B =Pth/(Pel+Pth) in "heat and power mode"
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E =MWel,aux.pwr/MWth in "heat and power mode"
F District heating steam temperature 185 °C; Cb=0.24; Cv=0.43; slightly higher efficiencies estimated, since steam turbine's isentropic efficiency decreases from high to low pressure.
G District heating water temperature 135 °C; Cb=0.32; Cv=0.59
H Design case! District heating water temperature 105°C; Cb=0.39; Cv=0.71
I District heating water temperature 70 °C; Cb=0.47; Cv=0.85
J Reference location is Austria
K Data is related to a condensing steam turbine with extraction at 1.7 bar running in "only electric power mode" (maximum electric power); for financial data using a backpressure steam turbine at proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 5%
L Data correction for different district heating temperatures estimated within error margin
M x… Electrical power generation [10 MW$_{el}$ … 100 MW$_{el}$]

6.1.1.2 Oil fired fired subcritical steam generators

In oil fired fired subcritical steam generators, oil is burnt in a furnace section. Heat from the combustion and the exhaust gas is used to produce subcritical steam from feed water. Steam is expanded in backpressure (1.7 bar) steam turbine for electricity production. Heat from backpressure steam is used via condensation for district heating. The alternative design is that heat is taken from steam turbine extraction at proper pressure level.

Future prospects for parameters are mainly based on a possible further (small) development on steam turbines' efficiencies and a reduction of auxiliary power. Combustion efficiency of oil is estimated as constant.

Assumptions for the data in the table below: Oil (LHV appr. 42 MJ/kg) fired subcritical steam generator(combustion eff. approx. 89%; 5% O_2 flue gas; steam 120 bar, 500 °C) with backpressure steam turbine (performance values reclined on Siemens SST-400 class).

Table 19: Overview of oil fired subcritical steam generators

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2 , 4
Heat generation capacity	MW_{th}	20 - 250												
Electrical power generation	MW_{el}	10 - 100												
Net electrical efficiency	%	24	24	24.5	25	25		23	26	24	27			
degree of fuel utilization accountable to el. Power	%	28	28	29	29	30		27	29	28	31		A	
degree of fuel utilization accountable to district heating	%	72	72	71	71	70		71	73	69	72		B	
Total degree of utilization, nominal load	%	89	89	89	89	89		85	91	86	92			
Total degree of utilization, annual average	%	81	81	81	81	81							C, D	
Electricity consumption	%	0.9	0.9	0.85	0.85	0.8		0.8	1.2	0.7	1		E	
Technical lifetime	years	25	25	25-30	>30	>30		25	30	25	35			
Steam supply		+	+	+	+	+		o	++	o	++		F	
Hot water		(o)	(o)	(o)	(o)	(o)		(o)	+	(o)	+		G	
Warm water		o	o	o	o	o		o	o	o	o		H	
Low temperature		-	-	-	-	-		-	o	-	o		I	
B. Environmental data														5, 6, 7
CO2	g/MJ_{th}	115	115	115	115	115		100	125	100	125			
SO2	g/GJ_{th}	105	105	100	90	90		100	120	80	100			
NOX	g/GJ_{th}	50	50	45	45	40		40	60	30	50			
CH4	g/GJ_{th}	<	<	<	<	<								
N2O	g/GJ_{th}	<	<	<	<	<								
Particles	g/GJ_{th}	5	5	5	5	5		3	6	3	5			
C. Financial data													J	1, 3, 8, 9
Quality of estimation		medium												
Nominal investment	$M€/MW_{el,max}$	1.99	1.99	1.90	1.90	1.81		1.63	2.35	1.45	2.17		K, L	
- of which equipment	$M€/MW_{el,max}$	1.36	1.36	1.27	1.27	1.18		1.09	1.54	1.00	1.45			
- of which installation	$M€/MW_{el,max}$	0.63	0.63	0.63	0.63	0.63		0.54	0.81	0.45	0.72			
Fixed O&M	**k**$€/MW_{el,max}/a$	9	9	8	8	7		5	14	5	14			
Variable O&M excl. electricity costs	$€/MWh_{el,max}$	0.6	0.6	0.6	0.6	0.6		0.4	1.1	0.4	1.1			
X. Technology specific data														
Cost function (estimation)	$M€/MW_{el}$	$Invest(x)=5.31x^{-0.20}$											M	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for steam turbine SST-400
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich", Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013

Notes:

A =Pel/(Pel+Pth) in "heat and power mode"
B =Pth/(Pel+Pth) in "heat and power mode"
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E =MWel,aux.pwr/MWth in "heat and power mode"
F District heating steam temperature 185 °C; Cb=0.24; Cv=0.43; slightly higher efficiencies estimated. since steam turbine's isentropic efficiency decreases from high to low pressure.
G District heating water temperature 135 °C; Cb=0.32; Cv=0.59
H Design case. District heating water temperature 105 °C; Cb=0.39; Cv=0.71
I District heating water temperature 70 °C; Cb=0.47; Cv=0.85
J Reference location is Central Europe
K Data is related to a condensing steam turbine with extraction at 1.7 bar running in "only electric power mode" (maximum electric power); for financial data using a backpressure steam turbine at proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 5%
L Data Correction for different district heating temperatures estimated within error margin
M x… Electrical power generation [10 MW_{el} … 100 MW_{el}]

6.1.1.3 Biomass fired fired subcritical steam generators

In biomass fired fired subcritical steam generators, biomass is burnt in a furnace section. Heat from the combustion and the exhaust gas is used to produce subcritical steam from feed water. Steam is expanded in backpressure (1.7 bar) steam turbine for electricity production. Heat from backpressure steam is used via condensation for district heating. The alternative design is that heat is taken from steam turbine extraction at proper pressure level.

Future prospects for parameters are mainly based on a possible further (small) development on steam turbines' efficiencies and a reduction of auxiliary power. Combustion efficiency of biomass is estimated as slightly increasing in future.

Assumptions for the data in the table below: Biomass (LHV appr. 14 MJ/kg) fired subcritical steam generator (combustion eff. approx. 92%; 6% O_2 flue gas; steam 120 bar, 520 °C) with backpressure steam turbine (performance values reclined on a CHPP in Austria).

Table 20: Overview of biomass fired subcritical steam generators

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2 , 4, 10, 11
Heat generation capacity	MW_{th}	20 - 100												
Electrical power generation	MW_{el}	10 - 50												
Net electrical efficiency	%	25	25	26	26	27		22	27	24	28			
degree of fuel utilization accountable to el. Power	%	28.5	29	29	29.5	30		27	30	28	31		A	
degree of fuel utilization accountable to district heating	%	71.5	71	71	70.5	70		70	73	69	72		B	
Total degree of utilization, nominal load	%	92	92	92.5	92.5	93		90	94	91	95			
Total degree of utilization, annual average	%	84	84	84.5	84.5	85							C, D	
Electricity consumption	%	1.9	1.9	1.8	1.8	1.7		1.6	2.3	1.4	2.1		E	
Technical lifetime	years	20-25	20-25	25	>25	>25		20	25	20	30			
Steam supply		+	+	+	+	+		o	++	o	++		F	
Hot water		(o)	(o)	(o)	(o)	(o)		(o)	+	(o)	+		G	
Warm water		o	o	o	o	o		o	o	o	o		H	
Low temperature		-	-	-	-	-		-	o	-	o		I	
B. Environmental data														5, 6, 7, 11
CO2	g/MJ_{th}	155	155	150	150	145		140	170	130	160			
SO2	g/GJ_{th}	6	6	5	5	4		4	10	4	10			
NOX	g/GJ_{th}	125	120	115	115	110		100	140	90	130			
CH4	g/GJ_{th}	<	<	<	<	<								
N2O	g/GJ_{th}	<	<	<	<	<								
Particles	g/GJ_{th}	5	5	5	5	5		3	12	3	12			
C. Financial data													J	1, 3, 8, 9, 10, 12
Quality of estimation		medium												
Nominal investment	$M€/MW_{el,max}$	3.6	3.6	3.4	3.2	3.0		2.7	4.5	2.3	4.1		K, L	
- of which equipment	$M€/MW_{el,max}$	2.7	2.7	2.5	2.3	2.1		2.0	3.0	1.6	2.7			
- of which installation	$M€/MW_{el,max}$	0.9	0.9	0.9	0.9	0.9		0.7	1.4	0.7	1.4			
Fixed O&M	$k€/MW_{el,max}/a$	45	45	36	36	27		27	72	18	54		M	
Variable O&M excl. electricity costs	$€/MWh_{el,max}$	0.6	0.6	0.6	0.6	0.6		0.4	1.1	0.4	1.1			
X. Technology specific data														
Cost function (estimation)	$M€/MW_{el}$	$Invest(x)=10.0x^{-0.25}$											N	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for steam turbine SST-400
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich“, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 Wien Energie: Biomasse Kraftwerk Simmering
11 Rechnungshofbericht Wien Energie Bundesforste Biomasse Kraftwerk
12 Wirtschaftlich effiziente Biomasse-Heizkraftwerke, Rolf Michler

Notes:

A =Pel/(Pel+Pth) in “heat and power mode”
B =Pth/(Pel+Pth) in “heat and power mode”
C based on planned availability of 8 000h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E =MWel,aux.pwr/MWth in “heat and power mode”
F District heating steam temperature 185 °C; Cb=0,24; Cv=0,43; slightly higher efficiencies estimated, since steam turbine’s isentropic efficiency decreases from high to low pressure.
G District heating water temperature 135 °C; Cb=0,33; Cv=0,59
H Design case! District heating water temperature 105°C; Cb=0,40; Cv=0,71
I District heating water temperature 70 °C; Cb=0,48; Cv=0,85
J Reference location is Austria
K Data is related to a condensing steam turbine with extraction at 1,7 bar running in “only electric power mode” (maximum electric power); for financial data using a backpressure steam turbine at proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 5%
L Data Correction for different district heating temperatures estimated within error margin
M Fuel handling / operation is estimated to be less cost intensive in future
N x… Electrical power generation [10 MW_{el} … 100 MW_{el}]

6.1.1.4 Coal (plus biomass and/or waste) fired subcritical steam generators

Pulverized coal fired combustion sections (with direct/indirect co-firing of biomass/waste) produce subcritical steam from feed water. Steam is expanded in backpressure steam turbine for electricity production. Heat from backpressure steam is used via condensation for district heating. The alternative design is that heat is taken from steam turbine extraction at proper pressure level.

Future prospects for parameters are mainly based on a possible further (small) development on steam turbines' efficiencies and a reduction of auxiliary power. Combustion efficiency of coal and biomass/waste additive is estimated as slightly increasing in future.

Assumptions for the data in the table below: Coal (plus optional biomass and/or waste, LHV appr. 30 MJ/kg) fired steam generator (combustion eff. approx. 93 %; 6% O_2 flue gas, steam 195 bar, 545 °C) with backpressure steam turbine (performance values reclined on an existing CHPP in Germany).

Table 21: Overview of coal fired subcritical steam generators

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2 , 4, 10, 11
Heat generation capacity	MW$_{th}$	250 – 1 500												
Electrical power generation	MW$_{el}$	100 – 1 000												
Net electrical efficiency	%	28	28	29	29	30		25	30	27	32			
degree of fuel utilization accountable to el. Power	%	32	32	33	33	34		30	34	32	36		A	
degree of fuel utilization accountable to district heating	%	68	68	67	67	66		66	70	64	68		B	
Total degree of utilization, nominal load	%	93	93	93.5	93.5	94		90	95	91	96			
Total degree of utilization, annual average	%	85	85	85.5	85.5	86							C, D	
Electricity consumption	%	2.9	2.9	2.8	2.8	2.7		2.5	3.5	2.3	3.3		E	
Technical lifetime	years	35	35	35	35	35		30	40	30	40			
Steam supply		+	+	+	+	+		o	++	o	++		F	
Hot water		(o)	(o)	(o)	(o)	(o)		(o)	+	(o)	+		G	
Warm water		o	o	o	o	o		o	o	o	o		H	
Low temperature		-	-	-	-	-		-	o	-	o		I	
B. Environmental data														5, 6, 7, 11
CO2	g/MJ$_{th}$	145	145	140	140	130		130	160	120	150			
SO2	g/GJ$_{th}$	85	85	80	80	75		50	100	30	100			
NOX	g/GJ$_{th}$	70	70	65	65	60		50	85	40	70			
CH4	g/GJ$_{th}$	<	<	<	<	<								
N2O	g/GJ$_{th}$	<	<	<	<	<								
Particles	g/GJ$_{th}$	4	4	4	4	4		3	6	2	5			
C. Financial data													J, K	1, 3, 8, 9, 10
Quality of estimation		medium												
Nominal investment	M€/MW$_{el,max}$	1.1	1.1	1.0	1.0	0.9		0.9	1.6	0.8	1.6		L, M	
- of which equipment	M€/MW$_{el,max}$	0.7	0.7	0.6	0.6	0.6		0.6	0.9	0.5	0.9			
- of which installation	M€/MW$_{el,max}$	0.4	0.4	0.4	0.4	0.3		0.3	0.6	0.2	0.6			
Fixed O&M	k€/MW$_{el,max}$/a	54	54	54	54	54		39	78	39	78			
Variable O&M excl. electricity costs	€/MWh$_{el,max}$	0.8	0.8	0.8	0.8	0.8		0.4	1.1	0.4	1.1			
X. Technology specific data														
Cost function	M€/MW$_{el}$	Invest(x)=2.17x$^{-0.10}$											N	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
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4 Brochure for steam turbine SST-400
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
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8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich", Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 EnBW Energie Baden-Württemberg AG: Kohlekraftwerk Heilbronn, Block 7
11 Kohlekraftwerk Voitsberg; Lecture TU Graz 1997

Notes:

A =Pel/(Pel+Pth) in "heat and power mode"
B =Pth/(Pel+Pth) in "heat and power mode"
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E =MWel.aux.pwr/MWth in "heat and power mode"
F District heating steam temperature 185 °C; Cb=0.31; Cv=0.48; slightly higher efficiencies estimated. since steam turbine's isentropic efficiency decreases from high to low pressure.
G District heating water temperature 135 °C; Cb=0.40; Cv=0.62
H Design case! District heating water temperature 105°C; Cb=0.47; Cv=0.74
I District heating water temperature 70 °C; Cb=0.56; Cv=0.86
J Reference location is Germany
K Optional additive fuel to coal (biomass or solid waste) is investigated together with pure coal fired steam generation. since performance modifications are marginal. Nominal investment for steam generation units that are capable to fire biomass or solid waste additives to coal are slightly higher than for pure coal fired units, but this difference is covered by the assumed error margin.
L Data is related to a condensing steam turbine with extraction at 1.7bar running in "only electric power mode" (maximum electric power); for financial data using a backpressure steam turbine at proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 3%
M Data Correction for different district heating temperatures estimated within error margin
N x… Electrical power generation [100 MW_{el} … 1000 MW_{el}]

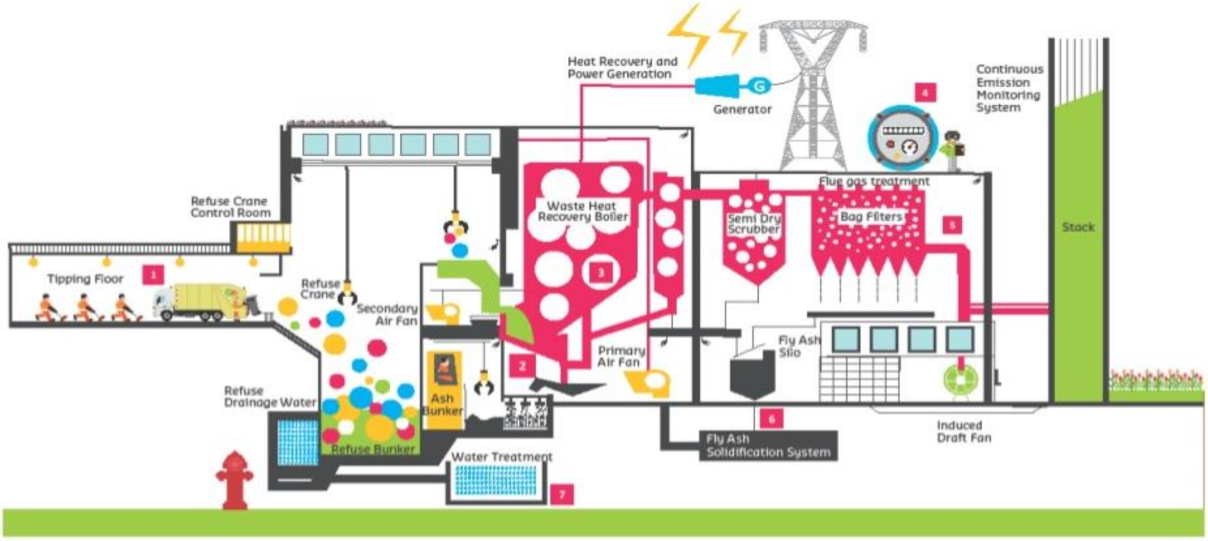
6.1.1.5 Solid waste fired subcritical steam generators

A waste-to-energy plant, primarily consisting of a waste reception area, a feeding system, a grate fired furnace interconnected with a steam boiler, a back pressure steam turbine, a generator, an extensive flue gas cleaning system and systems for handling of combustion and flue gas treatment residues produces electricity and heat for district heating simultaneously. The alternative design is that heat is taken from steam turbine extraction at proper pressure level.

Future prospects for parameters are mainly based on a possible further improvement of industrial waste separation, development on steam turbines' efficiencies and a reduction of auxiliary power. Combustion efficiency of solid waste is also estimated as slightly increasing in future.

Assumptions for the data in the table below: Solid waste (LHV approx. 13 MJ/kg) fired subcritical steam generator (combustion eff. approx. 89 %; 5% O_2 flue gas; steam 44 bar, 400 °C) with backpressure steam turbine (performance values reclined on a running waste-to-energy plant in Austria).

Figure 31: Visualisation of a waste-to-energy plant



Source: http://newsletter.sivecochina.com/en/customer-story/taiwanese_waste_to_energy_plant_optimizes_its_entire_operation_with_coswin/

Table 22: Overview of waste fired subcritical steam generators

	Unit	2015	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
A. Energy/technical data							**Lower**	**Upper**	**Lower**	**Upper**		1, 2 , 4, 10, 11, 13
Heat generation capacity	MW$_{th}$	10 - 50										
Electrical power generation	MW$_{el}$	5 - 25										
Net electrical efficiency	%	17.5	17.5	18	18.5	19	15	19	17	21		
degree of fuel utilization accountable to el. Power	%	23	23	23.5	23.5	24	22	24	23	25	A	
degree of fuel utilization accountable to district heating	%	77	77	76.5	76.5	76	76	78	75	77	B	
Total degree of utilization, nominal load	%	89	89	89.5	89.5	90	85	91	86	92		
Total degree of utilization, annual average	%	81	81	81.5	81.5	82					C, D	
Electricity consumption	%	3	3	2.5	2.5	2	2	4	1.5	4	E	
Technical lifetime	years	20	25	25	25	30	20	25	25	35		
Steam supply		+	+	+	+	+	o	++	o	++	F	
Hot water		(o)	(o)	(o)	(o)	(o)	(o)	+	(o)	+	G	
Warm water		o	o	o	o	o	o	o	o	o	H	
Low temperature		-	-	-	-	-	-	o	-	o	I	
B. Environmental data												5, 6, 7, 10, 11, 12
CO2	g/MJ$_{th}$	150	150	145	145	140	120	170	110	160		
SO2	g/GJ$_{th}$	12	11	10	8	6	10	15	5	15		
NOX	g/GJ$_{th}$	41	40	35	35	30	30	60	20	50		
CH4	g/GJ$_{th}$	<	<	<	<	<						
N2O	g/GJ$_{th}$	<	<	<	<	<						
Particles	g/GJ$_{th}$	4	4	3	3	3	3	8	2	8		
C. Financial data											J	1, 3, 8, 9, 10
Quality of estimation		medium										
Nominal investment	M€/MW$_{el,max}$	7.2	7.2	6.9	6.9	6.7	5.6	8.9	5.6	8.9	K, L	
- of which equipment	M€/MW$_{el,max}$	5	5	4.7	4.7	4.5	3.8	6.0	3.8	6.0		
- of which installation	M€/MW$_{el,max}$	2.2	2.2	2.2	2.2	2.2	1.8	2.9	1.8	2.9		
Fixed O&M	k€/MW$_{el,max}$/a	201	201	190	190	179	112	268	89	246		
Variable O&M excl. electricity costs	€/MWh$_{el,max}$	1	1	1	1	1	0.5	1.5	0.5	1.5		
X. Technology specific data												
Cost function (estimation)	M€/MW$_{el}$	Invest(x)=20.0x$^{-0.30}$									M	

References:

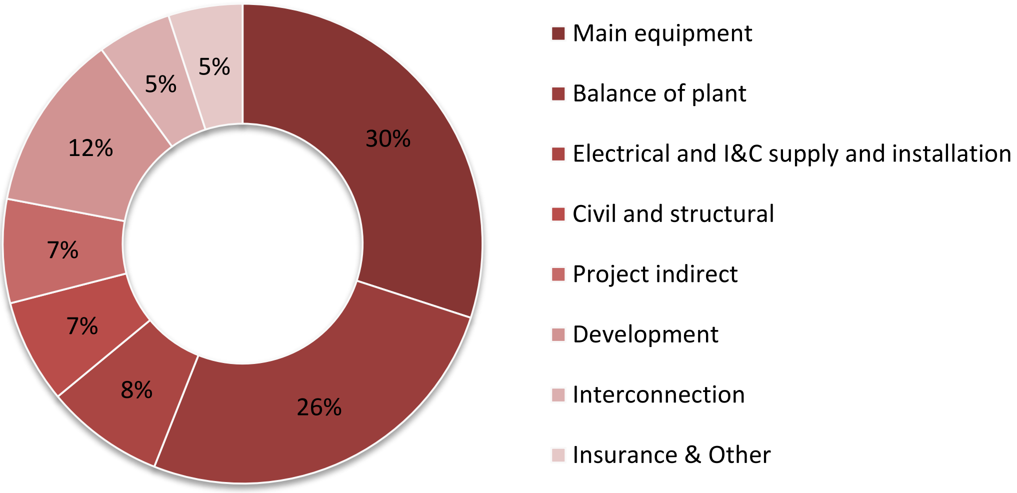
1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for steam turbine SST-400
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich‟, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 Operator’s data (direct): Waste to Energy Plant Niklasdorf
11 Umweltbundesamt: Leitfaden zur Umweltverträglichkeitserklärung für Abfallverbrennungsanlagen, thermische Kraftwerke und Feuerungsanlagen; Report 0193; 2008
12 Umweltbundesamt: Stand der Technik bei Abfallverbrennungsanlagen
13 World Bank Technical Guidance Report – Municipal Solid Waste Incineration

Notes:

A $=P_{el}/(P_{el}+P_{th})$ in “heat and power mode”
B $=P_{th}/(P_{el}+P_{th})$ in “heat and power mode”
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E $=MW_{el.aux.pwr/}MW_{th}$ in “heat and power mode”
F District heating steam temperature 185 °C; Cb=0.12; Cv=0.27; slightly higher efficiencies estimated. since steam turbine’s isentropic efficiency decreases from high to low pressure.
G District heating water temperature 135 °C; Cb=0.22; Cv=0.48
H Design case! District heating water temperature 105°C; Cb=0.29; Cv=0.64
I District heating water temperature 70 °C; Cb=0.36; Cv=0.81
J Reference location is Austria
K Data is related to a condensing steam turbine with extraction at 1.7 bar running in “only electric power mode” (maximum electric power); for financial data using a backpressure steam turbine at proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 7%
L Data Correction for different district heating temperatures estimated within error margin
M x… Electrical power generation [5 MW_{el} … 25 MW_{el}]

6.1.2 Supercritical steam generators (approx. > 100 MW thermal output)

Figure 32: CAPEX Breakdown of Supercritical Steam Generator[5]



For steam turbines driven by supercritical steam the same approach for the thermodynamic calculation is used as for subcritical steam generators as indicated in chapter above.

6.1.2.1 Natural gas fired supercritical steam generators

In natural gas fired supercritical steam generators, natural gas is burnt in a furnace section. Heat from the combustion and the exhaust gas is used to produce supercritical steam from feed water. Steam is expanded in backpressure steam turbine for electricity production. Heat from backpressure steam is used via condensation for district heating. The alternative design is that heat is taken from steam turbine extraction at proper pressure level.

Future prospects for parameters are mainly based on a possible further (small) development on steam turbines' efficiencies and a reduction of auxiliary power. Combustion efficiency of gas is estimated as constant.

Assumptions for the data in the table below: Natural gas (LHV appr. 40 MJ/kg) fired supercritical steam generator (combustion eff. approx. 95%; 3% O_2 flue gas; steam 285 bar, 600 °C) with backpressure steam turbine (performance values reclined on Siemens SST-6000).

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[5] Cost for the district heating connection itself (like net pumps and other auxiliary units) will be in the range of 1%

Table 23: Overview of natural gas fired supercritical steam generators

	Unit	**2015**	**2020**	**2030**	**2040**	**2050**		**Uncertainty (2020)**		**Uncertainty (2050)**			**Note**	**Ref**
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2 , 4
Heat generation capacity	MW$_{th}$	300 - 1 000												
Electrical power generation	MW$_{el}$	300 - 1 500												
Net electrical efficiency	%	31	31	32	32	32		29	33	30	35			
degree of fuel utilization accountable to el. Power	%	34	34	35	35	36		33	35	35	37		A	
degree of fuel utilization accountable to district heating	%	66	66	65	65	64		65	67	63	65		B	
Total degree of utilization, nominal load	%	95	95	95	95	95		92	96	93	97			
Total degree of utilization, annual average	%	87	87	87	87	87							C, D	
Electricity consumption	%	2,2	2,2	2	2	1,9		2	3	1,5	2,5		E	
Technical lifetime	years	25	25	25-30	>30	>30		25	30	25	35			
Steam supply		+	+	+	+	+		o	++	o	++		F	
Hot water		(o)	(o)	(o)	(o)	(o)		(o)	+	(o)	+		G	
Warm water		o	o	o	o	o		o	o	o	o		H	
Low temperature		-	-	-	-	-		-	o	-	o		I	
B. Environmental data														5, 6, 7
CO2	g/MJ$_{th}$	110	110	110	110	110		100	120	100	120			
SO2	g/GJ$_{th}$	<	<	<	<	<								
NOX	g/GJ$_{th}$	65	65	60	60	50		60	70	45	55			
CH4	g/GJ$_{th}$	<	<	<	<	<								
N2O	g/GJ$_{th}$	<	<	<	<	<								
Particles	g/GJ$_{th}$	<	<	<	<	<								
C. Financial data													J	1, 3, 8, 9
Quality of estimation		medium												
Nominal investment	M€/MW$_{el,max}$	1.01	1.01	0.94	0.94	0.94		0.87	1.45	0.72	1.45		K, L	
- of which equipment	M€/MW$_{el,max}$	0.72	0.72	0.65	0.65	0.65		0.58	1.02	0.50	1.02			
- of which installation	M€/MW$_{el,max}$	0.29	0.29	0.29	0.29	0.29		0.29	0.43	0.22	0.43			
Fixed O&M	k€/MW$_{el,max}$/a	6	6	6	6	5		4	10	4	10			
Variable O&M excl. electricity costs	€/MWh$_{el,max}$	0.5	0.5	0.5	0.5	0.5		0.3	1	0.3	1			
X. Technology specific data														
Cost function (estimation)	M€/MW$_{el}$	Invest(x)=2.91x$^{-0.15}$											M	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for steam turbine SST-6000 series
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich‟, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013

Notes:

A $=P_{el}/(P_{el}+P_{th})$ in “heat and power mode”
B $=P_{th}/(P_{el}+P_{th})$ in “heat and power mode”
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E $=MW_{el,aux.pwr}/MW_{th}$ in “heat and power mode”
F District heating steam temperature 185 °C; Cb=0.36; Cv=0.52; slightly higher efficiencies estimated. since steam turbine’s isentropic efficiency decreases from high to low pressure.
G District heating water temperature 135 °C; Cb=0.45; Cv=0.65
H Design case! District heating water temperature 105 °C; Cb=0.52; Cv=0.76
I District heating water temperature 70 °C; Cb=0.61; Cv=0.87
J Reference location is Germany
K Data is related to a condensing steam turbine with extraction at 1.7 bar running in “only electric power mode” (maximum electric power); for financial data using a backpressure steam turbine at proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 3%
L Data Correction for different district heating temperatures estimated within error margin
M x… Electrical power generation [300 MW_{el} … 1500 MW_{el}]

6.1.2.2 Oil fired supercritical steam generators

In oil fired supercritical steam generators, oil is burnt in a furnace section. Heat from the combustion and the exhaust gas is used to produce supercritical steam from feed water. Steam is expanded in backpressure steam turbine for electricity production. Heat from backpressure steam is used via condensation for district heating. The alternative design is that heat is taken from steam turbine extraction at proper pressure level.

Future prospects for parameters are mainly based on a possible further (small) development on steam turbines' efficiencies and a reduction of auxiliary power. Combustion efficiency of oil is estimated as constant.

Assumptions for the data in the table below: Oil (LHV appr. 42 MJ/kg) fired supercritical steam generator (combustion eff. approx. 89%; 5% O_2 flue gas; steam 285 bar, 600 °C) with backpressure steam turbine (performance values reclined on Siemens SST-6000 class).

Table 24: Overview of oil fired supercritical steam generators

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2 , 4
Heat generation capacity	MW$_{th}$	300 - 1 000												
Electrical power generation	MW$_{el}$	300 - 1 500												
Net electrical efficiency	%	29	29	30	30	31		28	31	30	33			
degree of fuel utilization accountable to el. Power	%	34	34	35	35	35		33	36	34	36		A	
degree of fuel utilization accountable to district heating	%	66	66	65	65	65		64	67	64	66		B	
Total degree of utilization, nominal load	%	89	89	89	89	89		88	92	88	92			
Total degree of utilization, annual average	%	81	81	81	81	81							C, D	
Electricity consumption	%	2.4	2.3	2.2	2.2	2.1		2	3	2	3		E	
Technical lifetime	years	25	25	25	25	25		25	>25	25	>25			
Steam supply		+	+	+	+	+		o	++	o	++		F	
Hot water		(o)	(o)	(o)	(o)	(o)		(o)	+	(o)	+		G	
Warm water		o	o	o	o	o		o	o	o	o		H	
Low temperature		-	-	-	-	-		-	o	-	o		I	
B. Environmental data														5, 6, 7
CO2	g/MJ$_{th}$	125	125	125	125	125		100	150	100	150			
SO2	g/GJ$_{th}$	70	70	60	60	60		60	90	50	80			
NOX	g/GJ$_{th}$	20	20	15	15	15		15	25	10	20			
CH4	g/GJ$_{th}$	<	<	<	<	<								
N2O	g/GJ$_{th}$	<	<	<	<	<								
Particles	g/GJ$_{th}$	3	3	3	3	3		2	5	2	4			
C. Financial data													J	1, 3, 8, 9
Quality of estimation		medium												
Nominal investment	M€/MW$_{el,max}$	1.16	1.16	1.01	1.01	1.01		1.01	1.59	0.72	1.45		K, L	
- of which equipment	M€/MW$_{el,max}$	0.80	0.80	0.72	0.72	0.72		0.65	1.08	0.50	1.02			
- of which installation	M€/MW$_{el,max}$	0.36	0.36	0.29	0.29	0.29		0.36	0.51	0.22	0.43			
Fixed O&M	k€/MW$_{el,max}$/a	6	6	5	5	5		4	12	4	10			
Variable O&M excl. electricity costs	€/MWh$_{el,max}$	0.6	0.6	0.6	0.6	0.6		0.4	1.1	0.4	1.1			
X. Technology specific data														
Cost function	M€/MW$_{el}$	$Invest(x)=3.06x^{-0.15}$											M	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for steam turbine SST-6000 series
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich‟, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013

Notes:

A =$P_{el}/(P_{el}+P_{th})$ in “heat and power mode”
B =$P_{th}/(P_{el}+P_{th})$ in “heat and power mode”
C based on planned availability of 8 000h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E =$MW_{el.aux.pwr/}MW_{th}$ in “heat and power mode”
F District heating steam temperature 185 °C; Cb=0.36; Cv=0.52; slightly higher efficiencies estimated. since steam turbine’s isentropic efficiency decreases from high to low pressure.
G District heating water temperature 135 °C; Cb=0.45; Cv=0.65
H Design case! District heating water temperature 105 °C; Cb=0.52; Cv=0.76
I District heating water temperature 70 °C; Cb=0.61; Cv=0.87
J Reference location is Germany
K Data is related to a condensing steam turbine with extraction at 1.7 bar running in “only electric power mode” (maximum electric power); for financial data using a backpressure steam turbine at proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 3%
L Data Correction for different district heating temperatures estimated within error margin
M x… Electrical power generation [300 MW_{el} … 1500 MW_{el}]

6.1.2.3 Coal fired supercritical steam generators

Pulverized coal fired combustion sections produce supercritical steam from feed water. Steam is expanded in backpressure steam turbine for electricity production. Heat from backpressure steam is used via condensation for district heating.

Future prospects for parameters are mainly based on a possible further (small) development on steam turbines' efficiencies and a reduction of auxiliary power. Combustion efficiency of coal is estimated as slightly increasing in future.

Assumptions for the data in the table below: Coal (LHV appr. 31 MJ/kg) fired supercritical steam generator (combustion eff. approx. 93.5%; 6% O_2 flue gas; steam 285 bar, 600 °C) with backpressure steam turbine (performance values reclined on an existing CHPP in Germany).

Table 25: Overview of coal fired supercritical steam generators

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2, 4, 10, 11, 12
Heat generation capacity	MW_{th}	500 - 3 000												
Electrical power generation	MW_{el}	300 - 1 500												
Net electrical efficiency	%	28	28	29	29	30		25	30	27	32			
degree of fuel utilization accountable to el. Power	%	33.2	33.5	34	34	35		32	34	33	37		A	
degree of fuel utilization accountable to district heating	%	66.8	66.5	66	66	65		66	68	63	67		B	
Total degree of utilization, nominal load	%	91	91	91.5	91.5	92		88	93	88	95			
Total degree of utilization, annual average	%	83	83	83.5	83.5	84							C, D	
Electricity consumption	%	3.5	3.5	3	3	2.5		2.5	4.5	1.5	4		E	
Technical lifetime	years	>35	>35	>35	>35	>35		25	40	25	40			
Steam supply		+	+	+	+	+		o	++	o	++		F	
Hot water		o	o	o	o	o		o	o	o	o		G	
Warm water		(o)	(o)	(o)	(o)	(o)		-	(o)	-	(o)		H	
Low temperature		-	-	-	-	-		-	o	-	o		I	
B. Environmental data														5, 6, 7, 11, 12
CO2	g/MJ_{th}	150	150	145	145	140		130	160	120	150			
SO2	g/GJ_{th}	88	85	80	80	75		50	100	30	100			
NOX	g/GJ_{th}	70	70	65	65	60		50	85	40	70			
CH4	g/GJ_{th}	<	<	<	<	<								
N2O	g/GJ_{th}	<	<	<	<	<								
Particles	g/GJ_{th}	4	4	4	3	3		3	6	2	5			
C. Financial data													J	1, 3, 8, 9, 10, 12
Quality of estimation		medium												
Nominal investment	M€/$MW_{el,max}$	1.11	1.11	1.04	1.04	0.97		0.97	1.53	0.83	1.39		K, L	
- of which equipment	M€/$MW_{el,max}$	0.76	0.76	0.69	0.69	0.69		0.55	0.98	0.55	0.90			
- of which installation	M€/$MW_{el,max}$	0.35	0.35	0.35	0.35	0.28		0.42	0.55	0.28	0.49			
Fixed O&M	k€/$MW_{el,max}$/a	55	55	55	55	55		42	69	42	69			
Variable O&M excl. electricity costs	€/$MWh_{el,max}$	0.8	0.8	0.8	0.8	0.8		0.4	1.1	0.4	1.1			
X. Technology specific data														
Cost function	M€/MW_{el}	$Invest(x)=2.21x^{-0.1}$											M	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050

2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012

3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011

4 Brochure for steam turbine SST-400

5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt

6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt

7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006

8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008

9 „Projektmanagement im Energiebereich‟, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013

10 EnBW Energie Baden-Württemberg AG: Kohlekraftwerk Heilbronn, Block 7

11 Kohlekraftwerk Voitsberg; Lecture TU Graz 1997

12 Bezirksregierung Münster: Kohlekraftwerk Datteln 4, Immissionsschutzrechtlicher Genehmigungsbescheid 2017

Notes:

A $=P_{el}/(P_{el}+P_{th})$ in "heat and power mode"

B $=P_{th}/(P_{el}+P_{th})$ in "heat and power mode"

C based on planned availability of 8 000h/a (DH+GEN)

D uncertainty depending on (unplanned) maintenance

E $=MW_{el.aux.pwr}/MW_{th}$ in "heat and power mode"

F District heating steam temperature 185 °C; Cb=0.32; Cv=0.45; slightly higher efficiencies estimated. since steam turbine's isentropic efficiency decreases from high to low pressure.

G District heating water temperature 135 °C; Cb=0.42; Cv=0.58

H Design case! District heating water temperature 105°C; Cb=0.50; Cv=0.69

I District heating water temperature 70 °C; Cb=0.59; Cv=0.80

J Reference location is Germany

K Data is related to a condensing steam turbine with extraction at 1.7bar running in "only electric power mode" (maximum electric power); for financial data using a backpressure steam turbine at proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 2%

L Data Correction for different district heating temperatures estimated within error margin

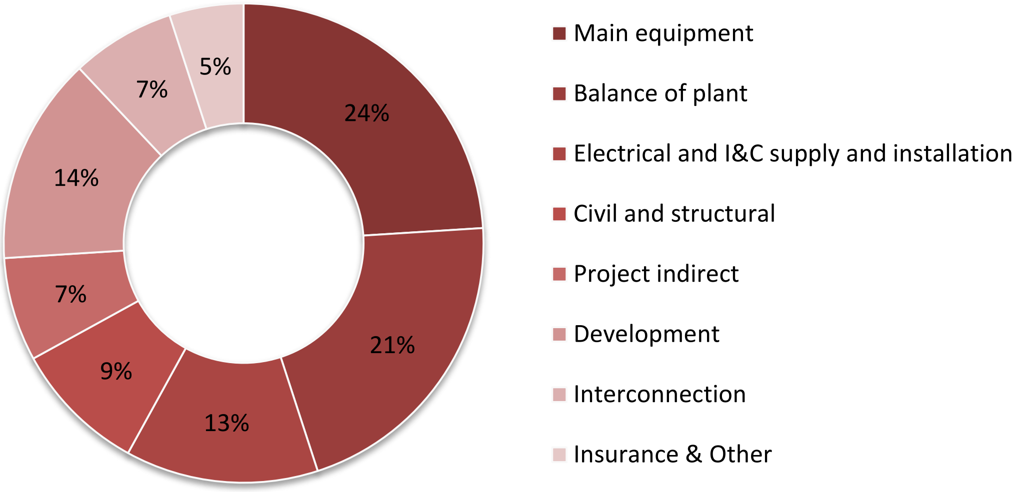
M x… Electrical power generation [300 MW_{el} … 1500 MW_{el}]

6.1.3 Natural gas fired gas turbines with direct heat recovery

For CHPPs using natural gas fired gas turbines in single cycle configuration (or open cycle configuration) the approach for the calculation of thermal power that can be used for district heating is (for better comparison) always a 105 °C level for the district heating temperature ("Warm water") and 120 °C for the exhaust flue gas stack temperature. The corresponding electrical power when running the plant in this single cycle heat recovery mode is approximately constant to a "once through" mode without thermal heat recovery for district heating.

The major components of such single cycle plants are an industrial (also called heavy duty) or an aero-derivative single-cycle gas turbine, a gearbox (when needed), and a generator plus for combined heat and power production a heat recovery boiler / heat exchanger ("Warm / Hot Water") that transfers heat from the hot flue gas to the district heating water.

Figure 33: CAPEX breakdown of natural gas fired single cycle gas GTs with direct heat recovery[6]



6.1.3.1 Small sized gas turbines with direct heat recovery

Future prospects for parameters are mainly based on a possible further (small) development on gas turbines' electrical efficiencies and a reduction of auxiliary power. Financial trend is taken from extrapolation from former and current data.

Assumptions for the data in the table below: Natural gas (LHV appr. 40 MJ/kg) fired "small" (up to 30 MW_{el}) single cycle gas turbine (SGT-300 class, appr. 15% O_2 flue gas; exhaust gas stack temperature after heat recovery 120 °C). Performance values of table the below are based on and calculated with gas turbine performance data from "GT performance library" and estimated inlet district heating temperature of 60 °C.

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[6] Cost for the district heating connection itself (like net pumps and other auxiliary units) will be in the range of 1%

Table 26: Overview of small sized gas turbines with direct heat recovery

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2, 4, 10
Heat generation capacity	MW$_{th}$	1 - 50												
Electrical power generation	MW$_{el}$	0.5 - 30												
Net electrical efficiency	%	31	31	32	33	33		29	33	31	36			
degree of fuel utilization accountable to el. Power	%	36	36	37	37	38		34	38	36	40		A	
degree of fuel utilization accountable to district heating	%	64	64	63	63	62		62	66	60	64		B	
Total degree of utilization, nominal load	%	85	85	85	85	85		83	88	83	90			
Total degree of utilization, annual average	%	77	77	77	77	77							C, D	
Electricity consumption	%	0.8	0.8	0.7	0.7	0.7		0.7	0.9	0.6	0.8		E	
Technical lifetime	years	30	30	35	35	35		25	35	30	40			
Steam supply		o	o	o	o	o		o	+	o	+		F	
Hot water		o	o	o	o	o		o	o	o	o			
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	(o)	(o)	(o)			
Low temperature		o	o	o	o	o		-	o	-	o			
B. Environmental data														5, 6, 7, 10
CO2	g/MJ$_{th}$	100	100	100	100	100		90	110	90	110			
SO2	g/GJ$_{th}$	<	<	<	<	<								
NOX	g/GJ$_{th}$	85	85	80	75	70		60	100	50	80			
CH4	g/GJ$_{th}$	<	<	<	<	<								
N2O	g/GJ$_{th}$	<	<	<	<	<								
Particles	g/GJ$_{th}$	<	<	<	<	<								
C. Financial data													G	1, 3, 8, 9, 10,11
Quality of estimation		medium												
Nominal investment	M€/MW$_{el,ISO}$	0.99	0.99	0.90	0.90	0.81		0.90	1.08	0.72	0.99		H, I	
- of which equipment	M€/MW$_{el,ISO}$	0.63	0.63	0.54	0.54	0.45		0.54	0.72	0.45	0.63			
- of which installation	M€/MW$_{el,ISO}$	0.36	0.36	0.36	0.36	0.36		0.36	0.36	0.27	0.36			
Fixed O&M	k€/MW$_{el,ISO}$/a	10	10	9	9	8		7	14	5	11			
Variable O&M excl. electricity costs	€/MWh$_{el,ISO}$	8	8	8	8	8		5	12	5	12		J	
X. Technology specific data														
Cost function	M€/MW$_{el}$	Invest(x)=3.05x$^{-0.35}$											K	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for gas turbine SGT-300
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich‟, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 Gas Turbine World 2014 – 2015 Handbook, Volume 31; 2015
11 Budget Offer Comp. Wulff & UMAG for Heat Exchanger

Notes:

A $=P_{el}/(P_{el}+P_{th})$ in “heat and power mode”
B $=P_{th}/(P_{el}+P_{th})$ in “heat and power mode”
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E $=MW_{el,aux.pwr/}MW_{th}$ in “heat and power mode”
F Cb factor approximately independent from district heating temperature. Cb mainly connected to gas turbine model (gas turbine efficiency). The higher gas turbine efficiency, the higher Cb factor. In this case for small GTs: Cb=0.55; Cv=1
G Reference location is Germany
H Financial data is given per electric power, GT running at ISO conditions
I Data Correction for different district heating temperatures is insignificant
J Split between fixed and variable O&M cost is depending on the maintenance contract with the GT manufacturer. Costs here are allocated to variable O&M
K x… Electrical power generation [0.5 MW_{el} … 30 MW_{el}]

6.1.3.2 Medium sized gas turbines with direct heat recovery

Future prospects for parameters are mainly based on a possible further (small) development on gas turbines' electrical efficiencies and a reduction of auxiliary power. Financial trend is taken from extrapolation from former and current data.

Assumptions for the data in the table below: Natural gas (LHV appr. 40 MJ/kg) fired "medium" (30 to 250 MW_{el}) single cycle gas turbine (SGT5-2000 class, appr. 15% O_2 flue gas; exhaust gas stack temperature after heat recovery 120 °C). Performance values of table below are based on and calculated with gas turbine performance data from GT performance library and estimated inlet district heating temperature of 60 °C.

Table 27: Overview of medium sized gas turbines with direct heat recovery

	Unit	**2015**	**2020**	**2030**	**2040**	**2050**		**Uncertainty (2020)**		**Uncertainty (2050)**			**Note**	**Ref**
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2, 4, 10
Heat generation capacity	MW$_{th}$	50 - 300												
Electrical power generation	MW$_{el}$	30 - 250												
Net electrical efficiency	%	34	35	35	36	36		32	36	38	40			
degree of fuel utilization accountable to el. Power	%	40	41	41	42	42		38	42	40	44		A	
degree of fuel utilization accountable to district heating	%	60	59	59	58	58		58	62	56	60		B	
Total degree of utilization, nominal load	%	85	85	85	85	85		83	88	83	90			
Total degree of utilization, annual average	%	77	77	77	77	77							C, D	
Electricity consumption	%	1	1	0.9	0.9	0.9		0.9	1.1	0.8	1		E	
Technical lifetime	years	30	30	35	35	35		25	35	30	40			
Steam supply		o	o	o	o	o		o	+	o	+		F	
Hot water		o	o	o	o	o		o	o	o	o			
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	(o)	(o)	(o)			
Low temperature		o	o	o	o	o		-	o	-	o			
B. Environmental data														5, 6, 7, 10
CO2	g/MJ$_{th}$	110	110	110	110	110		100	120	100	120			
SO2	g/GJ$_{th}$	<	<	<	<	<								
NOX	g/GJ$_{th}$	60	60	55	50	45		50	80	30	70			
CH4	g/GJ$_{th}$	<	<	<	<	<								
N2O	g/GJ$_{th}$	<	<	<	<	<								
Particles	g/GJ$_{th}$	<	<	<	<	<								
C. Financial data													G	1, 3, 8, 9, 10, 11
Quality of estimation		medium												
Nominal investment	M€/MW$_{el,ISO}$	0.45	0.45	0.37	0.37	0.37		0.37	0.52	0.30	0.45		H, I	
- of which equipment	M€/MW$_{el,ISO}$	0.30	0.30	0.22	0.22	0.22		0.25	0.34	0.20	0.30			
- of which installation	M€/MW$_{el,ISO}$	0.15	0.15	0.15	0.15	0.15		0.12	0.18	0.10	0.15			
Fixed O&M	k€/MW$_{el,ISO}$/a	8	7	7	7	6		6	9	4	7			
Variable O&M excl. electricity costs	€/MWh$_{el,ISO}$	7	7	7	7	7		5	8	5	8		J	
X. Technology specific data														
Cost function	M€/MW$_{el}$	Invest(x)=1.64x$^{-0.25}$											K	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for gas turbine SGT5-2000E
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich“, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 Gas Turbine World 2014 – 2015 Handbook, Volume 31; 2015
11 Budget Offer Comp. Wulff & UMAG for Heat Exchanger

Notes:

A =Pel/(Pel+Pth) in "heat and power mode"
B =Pth/(Pel+Pth) in "heat and power mode"
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E =MWel,aux.pwr/MWth in "heat and power mode"
F Cb factor approximately independent from district heating temperature. Cb mainly connected to gas turbine model (gas turbine efficiency). The higher gas turbine efficiency, the higher Cb factor. In this case for medium GTs: Cb=0.67; Cv=1
G Reference location is Germany
H Financial data is given per electric power, GT running at ISO conditions
I Data Correction for different district heating temperatures is insignificant
J Split between fixed and variable O&M cost is depending on the maintenance contract with the GT manufacturer. Costs here are allocated to variable O&M
K x… Electrical power generation [30 MW_{el} … 250 MW_{el}]

6.1.3.3 Large sized gas turbines with direct heat recovery

These “large scale” gas turbines are basically designed and optimized for a combined cycle configuration with a heat recovery steam generator (HRSG) and a steam turbine. Direct heat recovery configuration for district heating is rather unusual for these “large scale” gas turbines and presumes a couple of design changes of the gas turbine.

Future prospects for parameters are mainly based on a possible further (small) development on gas turbines’ electrical efficiencies and a reduction of auxiliary power. Financial trend is taken from extrapolation from former and current data.

Assumptions for the data in the table below: Natural gas (LHV appr. 40 MJ/kg) fired “large” (> 250 MW_{el}) single cycle gas turbine (SGT6-8000 class, appr. 15% O_2 flue gas; exhaust gas stack temperature after heat recovery 120 °C). Performance values of table below are based on and calculated with gas turbine performance data from GT performance library and estimated inlet district heating temperature of 60 °C.

Table 29: Overview of large sized gas turbines with direct heat recovery

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2, 4, 10
Heat generation capacity	MW_{th}	> 300												
Electrical power generation	MW_{el}	> 250												
Net electrical efficiency	%	40	40	41	41	42		38	42	40	44			
degree of fuel utilization accountable to el. Power	%	45	46	46	47	47		44	46	46	48		A	
degree of fuel utilization accountable to district heating	%	55	55	55	55	55		54	56	52	54		B	
Total degree of utilization, nominal load	%	89	89	89	89	89		85	90	85	90			
Total degree of utilization, annual average	%	81	81	81	81	81							C, D	
Electricity consumption	%	1.2	1.2	1.1	1.1	1.1		1	1.3	0.9	1.2		E	
Technical lifetime	years	30	30	35	35	35		25	35	30	40			
Steam supply		o	o	o	o	o		o	+	o	+		F	
Hot water		o	o	o	o	o		o	o	o	o			
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	(o)	(o)	(o)			
Low temperature		o	o	o	o	o		-	o	-	o			
B. Environmental data														5, 6, 7, 10
CO2	g/MJ_{th}	115	115	115	115	115		100	130	100	130			
SO2	g/GJ_{th}	<	<	<	<	<								
NOX	g/GJ_{th}	35	35	30	30	25		30	50	20	50			
CH4	g/GJ_{th}	<	<	<	<	<								
N2O	g/GJ_{th}	<	<	<	<	<								
Particles	g/GJ_{th}	<	<	<	<	<								
C. Financial data													G	1, 3, 8, 9, 10, 11
Quality of estimation		medium												
Nominal investment	$M€/MW_{el,ISO}$	0.39	0.38	0.37	0.37	0.36		0.37	0.43	0.31	0.43		H, I	
- of which equipment	$M€/MW_{el,ISO}$	0.27	0.26	0.25	0.25	0.24		0.25	0.28	0.20	0.28			
- of which installation	$M€/MW_{el,ISO}$	0.12	0.12	0.12	0.12	0.12		0.12	0.15	0.11	0.15			
Fixed O&M	$k€/MW_{el,ISO}/a$	5	5	4	4	4		4	7	3	6			
Variable O&M excl. electricity costs	$€/MWh_{el,ISO}$	5	5	5	5	5		3	6	3	6		J	
X. Technology specific data														
Cost function (estimation)	$M€/MW_{el}$	$Invest(x)=0.94x^{-0.15}$											K	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for gas turbine SGT6-800H
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich‟, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 Gas Turbine World 2014 – 2015 Handbook, Volume 31; 2015
11 Budget Offer Comp. Wulff & UMAG for Heat Exchanger

Notes:

A =$P_{el}/(P_{el}+P_{th})$ in “heat and power mode”
B =$P_{th}/(P_{el}+P_{th})$ in “heat and power mode”
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E =MWel,aux.pwr/MWth in “heat and power mode”
F Cb factor approximately independent from district heating temperature. Cb mainly connected to gas turbine model (gas turbine efficiency). The higher gas turbine efficiency, the higher Cb factor. In this case for large GTs: Cb=0.81; Cv=1
G Reference location is Germany
H Financial data is given per electric power, GT running at ISO conditions
I Data Correction for different district heating temperatures is insignificant
J Split between fixed and variable O&M cost is depending on the maintenance contract with the GT manufacturer. Costs here are allocated to variable O&M
K x… Electrical power generation [> 250 MW_{el}]

6.1.4 Natural gas fired gas turbines in combined cycle configuration

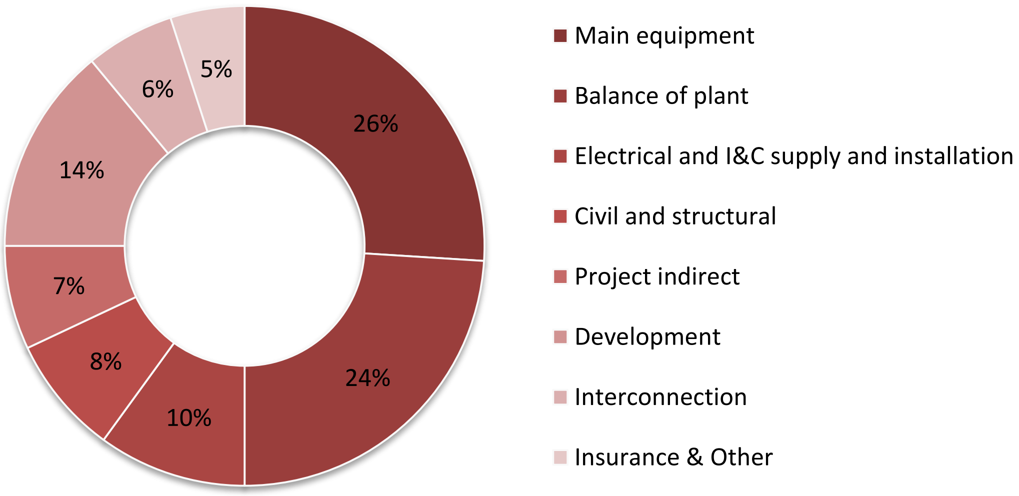
For CHPPs using natural gas fired gas turbines in combined cycle configuration the approach for the calculation of thermal power that can be used for district heating is (for better comparison) always a 105 °C level for the district heating temperature (“Warm water”) and a reasonable value for the exhaust flue gas stack temperature depending on the heat recovery steam generator (HRSG) configuration. Heat for the district heating system is recovered from the exhaust steam of a 1.7 bar backpressure steam turbine. The corresponding electrical power when running the plant in this combined cycle steam turbine backpressure heat recovery mode is the sum of the electrical powers of the gas turbine generator and the steam turbine generator.

The major components of combined cycle CHPPs are an industrial (also called heavy duty) or an aero-derivative gas turbine, a gearbox (when needed), and a generator plus for an HRSG with backpressure steam turbine and generator. A heat recovery boiler / heat exchanger (“Warm Water”) transfers heat from the exhaust backpressure steam (1.7 bar) of the steam turbine to the district heating water.

Future prospects for parameters are mainly based on a possible further (small) development on gas and steam turbines’ electrical efficiencies and a reduction of auxiliary power. Financial trend is taken from extrapolation from former and current data.

Assumptions for the data in the table below: Natural gas (LHV appr. 40 MJ/kg) fired combined cycle CHPP (SGT5-2000 GT class, appr. 15% O_2 flue gas; two-pressure HRSG with supplementary firing of natural gas; backpressure steam turbine with heat recovery heat exchanger / condenser for heat transfer to district heating system). Performance values of table below are based on and calculated with gas turbine performance data from “GT performance library” and appropriate modelled HRSG/ST- system. Estimated inlet district heating temperature is 60 °C.

Figure 34: CAPEX breakdown of natural gas fired gas turbines in combined cycle configuration[7]



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[7] Cost for the district heating connection itself (like net pumps and other auxiliary units) will be in the range of 1%

Table 28: Overview of natural gas fired gas turbines in combined cycle configuration

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2, 4, 10
Heat generation capacity	MW_{th}	50 - 500												
Electrical power generation	MW_{el}	50 - 500												
Net electrical efficiency	%	42	43	44	45	45		40	50	42	54			
degree of fuel utilization accountable to el. Power	%	54	54	55	56	56		52	56	54	58		A	
degree of fuel utilization accountable to district heating	%	46	46	45	44	44		44	48	42	46		B	
Total degree of utilization, nominal load	%	80	80	80	80	80		75	85	75	85			
Total degree of utilization, annual average	%	73	73	73	73	73							C, D	
Electricity consumption	%	2.3	2.3	2.2	2.2	2.2		2	3	2	3		E	
Technical lifetime	years	30	30	30	35	35		25	35	25	40			
Steam supply		+	+	+	+	+		o	++	o	++		F	
Hot water		(-)	(-)	(-)	(-)	(-)		(-)	+	(-)	+		G	
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	o	(o)	o		H	
Low temperature		-	-	-	-	-		-	o	-	o		I	
B. Environmental data														5, 6, 7, 10
CO2	g/MJ_{th}	150	150	140	140	140		120	170	120	170			
SO2	g/GJ_{th}	<	<	<	<	<								
NOX	g/GJ_{th}	75	75	70	70	65		60	90	50	80			
CH4	g/GJ_{th}	<	<	<	<	<								
N2O	g/GJ_{th}	<	<	<	<	<								
Particles	g/GJ_{th}	<	<	<	<	<								
C. Financial data													J	1, 3, 8, 9, 10
Quality of estimation		medium												
Nominal investment	M€/$MW_{el,max}$	1.2	1.2	1.1	1.1	1.0		1.1	1.3	0.9	1.2		K, L	
- of which equipment	M€/$MW_{el,max}$	0.8	0.8	0.7	0.7	0.7		0.8	0.9	0.6	0.8			
- of which installation	M€/$MW_{el,max}$	0.4	0.4	0.4	0.4	0.3		0.3	0.4	0.3	0.4			
Fixed O&M	k€/$MW_{el,max}$/a	5	5	4	4	4		4	7	4	6			
Variable O&M excl. electricity costs	€/$MWh_{el,max}$	5	5	5	5	5		3	6	3	6		M	
X. Technology specific data														
Cost function	M€/MW_{el}	Invest(x)=$3.75x^{-0.2}$											O	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for gas turbine SGT5-2000E
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich", Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 Gas Turbine World 2014 – 2015 Handbook, Volume 31; 2015

Notes:

A =$P_{el}/(P_{el}+P_{th})$ in "heat and power mode"
B =$P_{th}/(P_{el}+P_{th})$ in "heat and power mode"
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E =MWel,aux.pwr/MWth in "heat and power mode"
F District heating steam temperature 185 °C; Cb=1.06; Cv=0.79; slightly higher efficiencies estimated, since steam turbine's isentropic efficiency decreases from high to low pressure.
G District heating water temperature 135 °C; Cb=1,14; Cv=0,85
H Design case! District heating water temperature 105°C; Cb=1.18; Cv=0.88
I District heating water temperature 70 °C; Cb=1.27; Cv=0.94
J Reference location is Central Europe
K Data is related to a combined cycle power plant (CCPP) with condensing steam turbine with extraction at 1.7 bar running in "only electric power mode" (maximum electric power at STG); GT is running at ISO conditions; for financial data using a backpressure steam turbine at proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 2%
L Data Correction for different district heating temperatures estimated within error margin
M Split between fixed and variable O&M cost is depending on the maintenance contract with the GT manufacturer. Costs here are allocated to variable O&M
O x… Electrical power generation [50 MW_{el} … 500 MW_{el}]

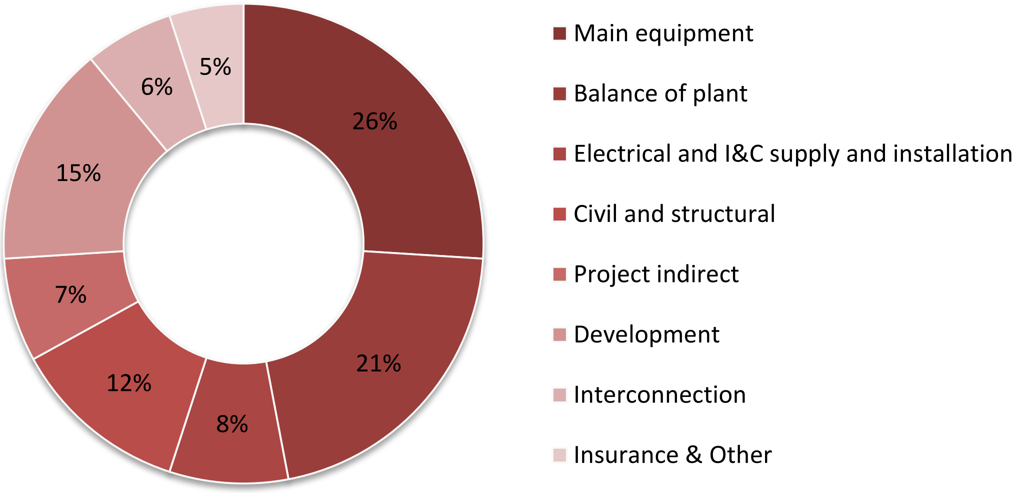
6.1.5 Gas engines

Gas engines are internal combustion engines (ICE) which run on gas fuels (such as coal-, producer-, bio-, landfill- or natural gas) and can both produce electrical and thermal power. The gas is combusted inside a reciprocating, spark plug ignited piston engine. The heat source for the heat recovery to the district heating is taken from 2two sources, namely the cooling water and oil cooler loop of the machine itself and heat from the engines flue gas. The cooling of the machine takes place at a lower temperature level, therefore usually two heat exchangers are used in series. The first heat exchanger is connected to the machine cooling loop and serves the low temperature coming in from the district heating. The second heat exchanger utilizes the flue gas to provide the final temperature.

There are three ways to operate a gas engine: no heat extraction, heat extraction only from the cooling loop and heat extraction both from the cooling loop and the flue gas. In the first case an auxiliary cooling system is required to provide engine cooling.

The approach for the following determination of thermal power, which can be used for district heating, is at a temperature level of 105 °C ("Warm / Hot water") with a power range from 1 to 10 MW_{th}. For the tables below it is assumed that the maximum possible amount of heat is extracted from the motors.

Figure 35: CAPEX breakdown of gas engines with heat recovery[8]



6.1.5.1 Natural gas fired gas engines

Future prospects for parameters are mainly based on a possible optimization of the internal combustion. Current assumptions suggest that an improvement of max. 4 percentage points is possible. Nevertheless an optimization of the combustion process leads in turn to a decreased level of thermal energy that can be extracted

Assumptions for the data in the table below: Natural gas (LHV appr. 40 MJ/kg) fired stationary gas engine. The performance data derived from typical gas engines used currently used in the market and validated with in-house data of respective machines.

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[8] Cost for the district heating connection itself (like net pumps and other auxiliary units) will be in the range of 1%

Table 29: Overview of natural gas fired engines with heat recovery

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2, 4, 10, 11, 14
Heat generation capacity	MW_{th}	1 - 9.0												
Electrical power generation	MW_{el}	0.8 - 11												
Net electrical efficiency	%	44	44	44	44	44		35	50	37	50			
degree of fuel utilization accountable to el. Power	%	49	49	51	53	53		43	55	47	49		A	
degree of fuel utilization accountable to district heating	%	51	51	49	47	47		45	57	41	53		B	
Total degree of utilization, nominal load	%	88	88	90	92	92		84	92	86	97			
Total degree of utilization, annual average	%	82	82	84	86	86							C, D	
Electricity consumption	%	0.2	0.2	0.2	0.2	0.2		0.1	0.3	0.1	0.3		E	
Technical lifetime	years	30	30	35	35	35		25	35	30	37			
Steam supply		N/A	N/A	N/A	N/A	N/A		N/A	N/A	N/A	N/A			
Hot water		--	--	--	--	--		--	--	--	--		F	
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	(o)	(o)	(o)			
Low temperature		(+)	(+)	(+)	(+)	(+)		(+)	(+)	(+)	(+)			
B. Environmental data														5, 6, 7, 12, 13
CO2	g/MJ_{th}	120	120	115	110	110		100	140	90	140			
SO2	g/GJ_{th}	<	<	<	<	<								
NOX	g/GJ_{th}	180	160	125	125	125		100	250	50	200			
CH4	g/GJ_{th}	<	<	<	<	<								
N2O	g/GJ_{th}	<	<	<	<	<								
Particles	g/GJ_{th}	<	<	<	<	<								
C. Financial data													G	1, 3, 8, 9, 13
Quality of estimation		medium												
Nominal investment	$M€/MW_{el,ISO}$	0.7	0.7	0.5	0.5	0.5		0.5	1.0	0.4	0.9		H, I	
- of which equipment	$M€/MW_{el,ISO}$	0.6	0.6	0.4	0.4	0.4		0.4	0.7	0.3	0.7			
- of which installation	$M€/MW_{el,ISO}$	0.1	0.1	0.1	0.1	0.1		0.1	0.2	0.1	0.2			
Fixed O&M	$k€/MW_{el,ISO}/a$	9	9	9	9	9		7	12	7	12			
Variable O&M excl. electricity costs	$€/MWh_{el,ISO}$	7	7	7	7	7		6	13	6	13		J	
X. Technology specific data														
Cost function	$M€/MW_{el}$	$Invest(x)=1.11x^{-0.30}$											M	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for Gas Engines, GE Energy, Jenbacher
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich“, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 Clarke Energy, Gas Engines
11 Data sheet jenbacher Gas Engines Type 2 to Type 9 / J920
12 Industrieverband (VDAMA): Abgasgesetzgebung Diesel- und Gasmotoren
13 Klima- und Energiefonds: Blue Globe Report- Energieeffizienz: Gasmotor der Zukunft; 2008
14 MWM: Aufbau von Energieanlagen mit Gasmotor-Antrieb

Notes:

A $=P_{el}/(P_{el}+P_{th})$ in “heat and power mode”
B $=P_{th}/(P_{el}+P_{th})$ in “heat and power mode”, Heat output separated into engine cooling system (~ 50% output) and exhaust gas heat exchanger output (~ 50%)
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E $=_{MWel,aux.pwr}/MW_{th}$ in “heat and power mode”
F Cb factor approximately independent from district heating temperature. Cb mainly connected to gas engine exhaust temperature. In this case: Cb=1.22; Cv=1.0 Efficiency mainly depends on incoming water temperatures. Gas engine cooling system can operate near to 70 °C, higher temperatures have been cooled down.
G Reference location is Germany
H Financial data is given per electric power, gas engine running at ISO conditions
I Data Correction for different district heating temperatures is insignificant. Thermal output have to be changed
J ASUE BHKW Kenndaten 2014/15, cost function y=8.63*MWel^(-0.317) adapted by a multiplier of 1.5 because of other related systems (Selective catalytic reduction (SCR), pumps, etc.), Reference value= 6 MW.
M x… Electrical power generation [1 MW_{el} … 11 MW_{el}]

6.1.5.2 Biogas fired gas engines

Future prospects for parameters are mainly based on a possible optimization of the internal combustion. Current assumptions suggest that an improvement of max. 4 percentage points is possible. Nevertheless an optimization of the combustion process leads in turn to a decreased level of thermal energy that can be extracted

Assumptions for the data in the table below: Biogas (LHV appr. 17.9 MJ/kg) fired stationary gas engine. It is assumed that in order to achieve low SOx emissions the biogas is desulphurized to 0.05 % sulphur in the fuel gas. The performance data derived from typical gas engines currently used in the market and validated with in-house data of respective machines. The gas engines used for firing biogas are the same as for natural gas, with the exception of the flue gas duct which is designed for higher exit temperatures and SOx content.

Table 30: Overview of biogas fired engines with heat recovery

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2, 4, 10, 11, 14
Heat generation capacity	MW$_{th}$	0.4 - 9.0												
Electrical power generation	MW$_{el}$	0.3 - 11												
Net electrical efficiency	%			41				35	50	40	50			
degree of fuel utilization accountable to el. Power	%	49	49	51	53	53		43	55	47	59		A	
degree of fuel utilization accountable to district heating	%	51	51	49	47	47		45	57	41	53		B	
Total degree of utilization, nominal load	%	85	85	86	88	88		81	92	83	92			
Total degree of utilization, annual average	%	79	79	80	82	82							C, D	
Electricity consumption	%	0.2	0.2	0.2	0.2	0.2		0.1	0.3	0.1	0.3		E	
Technical lifetime	years	25	25	30	30	30		20	30	25	35			
Steam supply		N/A	N/A	N/A	N/A	N/A		N/A	N/A	N/A	N/A			
Hot water		--	--	--	--	--		--	--	--	--		F	
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	(o)	(o)	(o)			
Low temperature		(+)	(+)	(+)	(+)	(+)		(+)	(+)	(+)	(+)			
B. Environmental data														5, 6, 7, 12, 13
CO2	g/MJ$_{th}$	210	210	200	190	190		180	240	100	210			
SO2	g/GJ$_{th}$	160	140	120	120	120		110	170	90	150			
NOX	g/GJ$_{th}$	205	170	150	150	150		100	250	100	190			
CH4	g/GJ$_{th}$	<	<	<	<	<								
N2O	g/GJ$_{th}$	<	<	<	<	<								
Particles	g/GJ$_{th}$	<	<	<	<	<								
C. Financial data													G	5, 3, 8, 9, 13
Quality of estimation		medium												
Nominal investment	M€/MW$_{el,ISO}$	0.8	0.8	0.7	0.7	0.7		0.6	1.2	0.5	1.1		H, I	
- of which equipment	M€/MW$_{el,ISO}$	0.7	0.7	0.6	0.6	0.6		0.5	1.0	0.4	0.9			
- of which installation	M€/MW$_{el,ISO}$	0.1	0.1	0.1	0.1	0.1		0.1	0.2	0.1	0.2			
Fixed O&M	k€/MW$_{el,ISO}$/a	9	9	9	9	9		6	12	2	9			
Variable O&M excl. electricity costs	€/MWh$_{el,ISO}$	13.1	13.1	13.1	13.1	13.1		11	29	11	29		J	
X. Technology specific data														
Cost function	M€/MW$_{el}$	$Invest(x)=1.27x^{-0.30}$											K	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for Gas Engines, GE Energy, Jenbacher
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich“, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 Clarke Energy, Gas Engines
11 Data sheet jenbacher Gas Engines Type 2 to Type 9 / J920
12 Industrieverband (VDAMA): Abgasgesetzgebung Diesel- und Gasmotoren
13 Klima- und Energiefonds: Blue Globe Report- Energieeffizienz: Gasmotor der Zukunft; 2008
14 MWM: Aufbau von Energieanlagen mit Gasmotor-Antrieb

Notes:

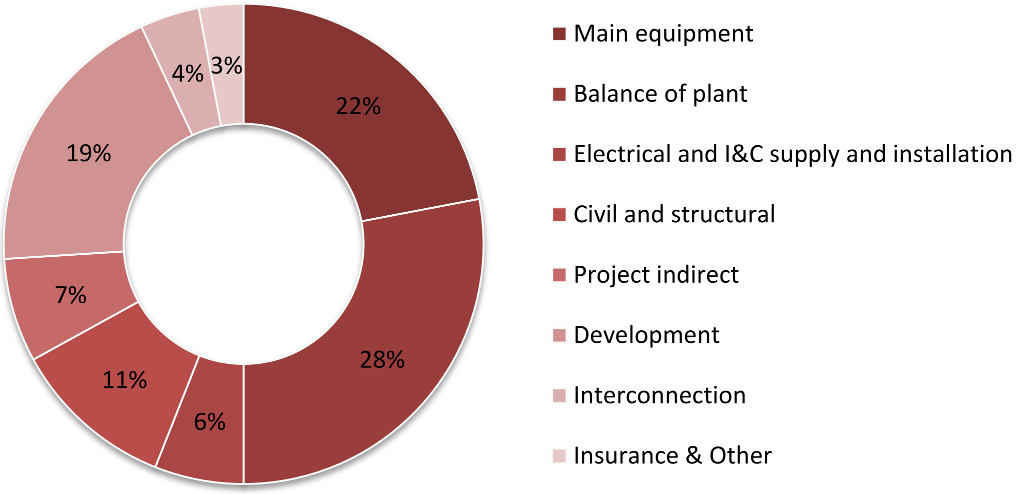
A =Pel/(Pel+Pth) in "heat and power mode"
B =Pth/(Pel+Pth) in "heat and power mode"
C based on planned availability of 8 000h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E =MWel,aux.pwr/MWth in "heat and power mode"
F Cb factor approximately independent from district heating temperature. Cb mainly connected to gas engine exhaust temperature. In this case: Cb=1.22; Cv=1.0
G Reference location is Germany
H Financial data is given per electric power, gas engine running at ISO conditions
I Data Correction for different district heating temperatures is insignificant
J ASUE BHKW Kenndaten 2014/15, cost function y=19.4*MWel^(-0.411) adapted by a multiplier of 1.5 because of other related systems (SCR, pumps, etc.), indicated Reference value= 7 MW.
K x… Electrical power generation [1 MW_{el} … 11 MW_{el}]

6.1.6 Integrated gasification plants

The integrated gasification cycle (IGC) is a process with upstream fuel gasification. In this process, the primary fuel (such as coal, biomass or waste) is converted into energetic fuel gas (synthetic gas or "syngas") under stoichiometry (λ approximately between 0.2 and 0.4) in a carburetor. This gas could be used in gas turbines / steam generators with optionally modified combustion section. Both electrical and thermal power could be generated with the available CHP applications.

For CHPPs using backpressure steam turbines the approach for the calculation of thermal power, that can be used for district heating, is 105 °C for the district heating temperature ("Warm water") with a minimum of 10 °C spread of the backpressure steam temperature of the steam turbine (115 °C saturated at 1.7 bar). The corresponding electrical power when running the plant in this backpressure mode is used for the calculation of further parameters of the tables below. Maximum electrical power (see also Cv factor) of such a CHPP using a condensing steam turbine with steam extraction can be produced in "condensing mode" (without any thermal heat production for district heating).

Figure 36: CAPEX breakdown of integrated gasification CHP plants[9]



6.1.6.1 Gasified biomass fired CHPPs

Future prospects for parameters are mainly based on a possible further development of the biomass gasification process, on the reduction of auxiliary power and on possible small increase of steam turbines' efficiencies. Combustion efficiency of syngas is estimated as constant in future.

Assumptions for the data in the table below: Syngas from gasified solid biomass (LHV appr. 6.2 MJ/kg) fired subcritical steam generator (combustion eff. approx. 85%; 3% O_2 flue gas; steam 40 bar, 455 °C) with backpressure steam turbine (performance values are reclined on a biomass CHPP in Sweden). The alternative design is that heat is taken from steam turbine extraction at proper pressure level.

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[9] Cost for the district heating connection itself (like net pumps and other auxiliary units) will be in the range of 1%

Table 31: Overview of gasified biomass fired CHPPs

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2 , 4, 10, 11, 13, 14, 15
Heat generation capacity	MW$_{th}$	5 - 30												
Electrical power generation	MW$_{el}$	1 - 15												
Net electrical efficiency	%	18	18	19	19	20		17	20	19	22			
degree of fuel utilization accountable to el. Power	%	23	23	24	24	24		22	24	23	25		A	
degree of fuel utilization accountable to district heating	%	77	77	76	76	76		76	78	75	77		B	
Total degree of utilization, nominal load	%	85	85	85	85	85		80	90	80	90			
Total degree of utilization, annual average	%	78	78	78	78	78							C, D	
Electricity consumption	%	2.3	2.2	2.1	2	2		2	3	1.5	2.5		E	
Technical lifetime	years	20	25	25	25	30		20	25	25	30			
Steam supply		+	+	+	+	+		o	++	o	++		F	
Hot water		o	o	o	o	o		o	+	o	+		G	
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	(o)	(o)	(o)		H	
Low temperature		-	-	-	-	-		-	o	-	o		I	
B. Environmental data														5, 6, 7, 11, 13
CO2	g/MJ$_{th}$	170	170	170	170	170		140	200	140	200			
SO2	g/GJ$_{th}$	<	<	<	<	<		<	<	<	<			
NOX	g/GJ$_{th}$	70	70	65	65	60		50	100	40	90			
CH4	g/GJ$_{th}$	<	<	<	<	<								
N2O	g/GJ$_{th}$	<	<	<	<	<								
Particles	g/GJ$_{th}$	<	<	<	<	<								
C. Financial data													J	1, 3, 8, 9, 10, 12
Quality of estimation		medium												
Nominal investment	M€/MW$_{el,max}$	5.3	5.3	5.1	4.9	4.7		4.3	6.5	3.7	5.8		K, L	
- of which equipment	M€/MW$_{el,max}$	3.4	3.4	3.2	3.0	3.0		3.0	4.3	2.6	3.9			
- of which installation	M€/MW$_{el,max}$	1.9	1.9	1.9	1.9	1.7		1.3	2.2	1.1	1.9			
Fixed O&M	k€/MW$_{el,max}$/a	108	108	97	97	86		65	129	43	108		M	
Variable O&M excl. electricity costs	€/MWh$_{el,max}$	4	4	4	4	4		3	6	3	6			
X. Technology specific data														
Cost function	M€/MW$_{el}$	Invest(x)=8.77x$^{-0.25}$											N	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for steam turbine SST-400
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
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7 Integrated Pollution Prevention and Control – Reference Document on BAT teechniques for large combustion plants; 2006
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9 „Projektmanagement im Energiebereich", Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 Wien Energie: Biomasse Kraftwerk Simmering
11 Rechnungshofbericht Wien Energie Bundesforste Biomasse Kraftwerk
12 Wirtschaftlich effiziente Biomasse-Heizkraftwerke, Rolf Michler
13 Biomass IGCC at Varnamo, Sweden
14 Arbeitsgemeinschaft Erneuerbare Energie Dachverband
15 County Meath, Ireland; B&W Volund
16 Biomasse Kraftwerk Güssing; Repotec

Notes:

A $=P_{el}/(P_{el}+P_{th})$ in "heat and power mode"
B $=P_{th}/(P_{el}+P_{th})$ in "heat and power mode"
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E $=MW_{el.aux.pwr/}MW_{th}$ in "heat and power mode"
F District heating steam temperature 185 °C; Cb=0.12; Cv=0.27; slightly higher efficiencies estimated. since steam turbine's isentropic efficiency decreases from high to low pressure.
G District heating water temperature 135 °C; Cb=0.23; Cv=0.49
H Design case! District heating water temperature 105 °C; Cb=0.3; Cv=0.64
I District heating water temperature 70 °C; Cb=0.38; Cv=0.81
J Reference location is Sweden
K Data is related to a condensing steam turbine with extraction at 1.7 bar running in "only electric power mode" (maximum electric power); for financial data using a backpressure steam turbine at proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 7%
L Data Correction for different district heating temperatures estimated within error margin
M Fuel handling / operation is estimated to be less cost intensive in future
N x… Electrical power generation [1…15 MW_{el}]

6.1.6.2 Gasified solid waste fired CHPPs

Future prospects for parameters are mainly based on a possible further development of the solid waste gasification process, on the reduction of auxiliary power and on possible small increase of steam turbines' efficiencies. Combustion efficiency of syngas is estimated as constant in future.

Assumptions for the data in the table below: Syngas from gasified solid waste (LHV appr. 6.9 MJ/kg) fired subcritical steam generator (combustion eff. approx. 85%; 3% O_2 flue gas; steam 121 bar, 540 °C) with backpressure steam turbine (performance values are reclined on waste-to-energy CHPPs in Ireland and Finland).

Table 32: Overview of gasified solid waste fired CHPPs

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2 , 4, 10, 11, 13, 14, 15
Heat generation capacity	MW$_{th}$	50 - 200												
Electrical power generation	MW$_{el}$	25 - 100												
Net electrical efficiency	%	23	23	23	24	24		21	25	22	26			
degree of fuel utilization accountable to el. Power	%	29	29	29	30	30		28	30	29	31		A	
degree of fuel utilization accountable to district heating	%	71	71	71	70	70		70	72	69	711		B	
Total degree of utilization, nominal load	%	85	85	85	85	85		83	87	83	87			
Total degree of utilization, annual average	%	78	78	78	78	78							C, D	
Electricity consumption	%	3.5	3.5	3.3	3.1	3.0		2	4	1	3		E	
Technical lifetime	years	20	20	25	25	30		20	30	25	35			
Steam supply		+	+	+	+	+		o	++	o	++		F	
Hot water		o	o	o	o	o		o	+	o	+		G	
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	(o)	(o)	(o)		H	
Low temperature		-	-	-	-	-		-	o	-	o		I	
B. Environmental data														5, 6, 7, 10, 11, 12, 14
CO2	g/MJ$_{th}$	180	180	180	180	180		150	250	150	250			
SO2	g/GJ$_{th}$	<	<	<	<	<								
NOX	g/GJ$_{th}$	100	100	90	80	70		80	120	50	100			
CH4	g/GJ$_{th}$	<	<	<	<	<								
N2O	g/GJ$_{th}$	<	<	<	<	<								
Particles	g/GJ$_{th}$	<	<	<	<	<								
C. Financial data													J	1, 3, 8, 9, 10
Quality of estimation		medium												
Nominal investment	M€/MW$_{el,max}$	6.0	6.0	5.7	5.3	5.2		4.3	6.8	3.4	6.8		K, L	
- of which equipment	M€/MW$_{el,max}$	3.9	3.9	3.6	3.4	3.3		2.9	4.6	2.4	4.6			
- of which installation	M€/MW$_{el,max}$	2.1	2.1	2.1	1.9	1.9		1.4	2.2	1.0	2.2			
Fixed O&M	k€/MW$_{el,max}$/a	163	163	154	154	154		86	206	86	206			
Variable O&M excl. electricity costs	€/MWh$_{el,max}$	3	3	3	3	3		1	5	1	5			
X. Technology specific data														
Cost function	M€/MW$_{el}$	$Invest(x)=14.23x^{-0.2}$											M	

References:

1 Energy Technology Reference Indicator, Projections for 2010-2050
2 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012
3 Cost Report- Cost And Performance Data For Power Generation Technologies; Prepared for the National Renewable Energy Laboratory February 2012; Black&Veatch Holding Company 2011
4 Brochure for steam turbine SST-400
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
6 Emissionsfaktoren als Grundlage für die österreichische Luftschadstoff – Inventur, Umwelbundesamt
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8 Stromerzeugungskosten im Vergleich, Uni Stuttgart, Feb 2008
9 „Projektmanagement im Energiebereich“, Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
10 Operator's data (direct): Waste to Energy Plant Niklasdorf
11 Umweltbundesamt: Leitfaden zur Umweltverträglichkeitserklärung für Abfallverbrennungsanlagen, thermische Kraftwerke und Feuerungsanlagen; Report 0193; 2008
12 Umweltbundesamt: Stand der Technik bei Abfallverbrennungsanlagen
13 World Bank Technical Guidance Report – Municipal Solid Waste Incineration
14 Saacke: Vergasung fester Abfälle; Power Plant Lahti
15 County Meath, Ireland; B&W Volund

Notes:

A =Pel/(Pel+Pth) in "heat and power mode"
B =Pth/(Pel+Pth) in "heat and power mode"
C based on planned availability of 8 000h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E =MWel,aux.pwr/MWth in "heat and power mode"
F District heating steam temperature 185 °C; Cb=0.25; Cv=0.44; slightly higher efficiencies estimated, since steam turbine's isentropic efficiency decreases from high to low pressure.
G District heating water temperature 135 °C; Cb=0.35; Cv=0.60
H Design case! District heating water temperature 105 °C; Cb=0.42; Cv=0.72
I District heating water temperature 70 °C; Cb=0.50; Cv=0.85
J Reference location is Ireland / Finland
K Data is related to a condensing steam turbine with extraction at 1.7 bar running in "only electric power mode" (maximum electric power); for financial data using a backpressure steam turbine at proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 5%
L Data Correction for different district heating temperatures estimated within error margin
M x… Electrical power generation [25…100 MW_{el}]

6.1.6.3 Gasified coal fired CHPPs

Future prospects for parameters are mainly based on a possible further (small) development on gas and steam turbines' electrical efficiencies and a reduction of auxiliary power. Further development of coal gasification process is also taken into account. Financial trend is taken from extrapolation from former and current data.

Assumptions for the data in the table below: Syngas from gasified coal (LHV appr. 20 MJ/kg) fired combined cycle CHPP (IGCC – Integrated Gasification Combined Cycle) with SGT5-2000 GT class, appr. 15% O2 flue gas; two-pressure HRSG with supplementary firing of syngas; condensing steam turbine with extraction and heat recovery heat exchanger / condenser for heat transfer to district heating system). Performance values of table below are based on and calculated with gas turbine performance data from "GT performance library" and appropriate modelled HRSG /ST- system. Estimated inlet district heating temperature is 60 °C. Performance values are reclined on IGCCs in Germany and USA.

Table 33: Overview of gasified coal fired CHPPs

	Unit	2015	2020	2030	2040	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
A. Energy/technical data							**Lower**	**Upper**	**Lower**	**Upper**		1, 2, 4, 10, 11, 12, 13
Heat generation capacity	MW$_{th}$	100 - 500										
Electrical power generation	MW$_{el}$	100 - 500										
Net electrical efficiency	%	41	41	42	42	42	38	44	39	45		
degree of fuel utilization accountable to el. Power	%	54	54	55	55	55	52	56	53	57	A	
degree of fuel utilization accountable to district heating	%	46	46	45	45	45	44	48	43	47	B	
Total degree of utilization, nominal load	%	80	80	80	80	80	75	85	75	85		
Total degree of utilization, annual average	%	73	73	73	73	73					C, D	
Electricity consumption	%	4	4	3.5	3.5	3.5	2	5	1.5	4.5	E	
Technical lifetime	years	30	30	35	35	35	25	35	30	40		
Steam supply		+	+	+	+	+	o	++	o	++	F	
Hot water		o	o	o	o	o	o	+	o	+	G	
Warm water		(o)	(o)	(o)	(o)	(o)	(o)	(o)	(o)	(o)	H	
Low temperature		-	-	-	-	-	-	o	-	o	I	
B. Environmental data												5, 6, 7, 10, 11, 12, 13
CO2	g/MJ$_{th}$	200	200	200	200	200	50	300	50	300		
SO2	g/GJ$_{th}$	<	<	<	<	<						
NOX	g/GJ$_{th}$	20	20	18	18	15	15	50	10	45		
CH4	g/GJ$_{th}$	<	<	<	<	<						
N2O	g/GJ$_{th}$	<	<	<	<	<						
Particles	g/GJ$_{th}$	<	<	<	<	<						
C. Financial data											J	1, 3, 8, 9, 10, 11
Quality of estimation		medium										
Nominal investment	M€/MW$_{el,max}$	2.5	2.5	2.4	2.4	2.2	2.2	3.7	1.9	3.0	K, L	
- of which equipment	M€/MW$_{el,max}$	1.6	1.6	1.5	1.5	1.4	1.5	2.6	1.3	2.0		
- of which installation	M€/MW$_{el,max}$	0.9	0.9	0.9	0.9	0.8	0.7	1.1	0.6	1.0		
Fixed O&M	k€/MW$_{el,max}$/a	6	6	6	6	6	4	7	4	7		
Variable O&M excl. electricity costs	€/MWh$_{el,max}$	5	5	5	5	5	4	7	4	7		
X. Technology specific data												
Cost function	M€/MW$_{el}$	Invest(x)=5.88x$^{-0.15}$									M	

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1 Energy Technology Reference Indicator, Projections for 2010-2050
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10 Gas Turbine World 2014 – 2015 Handbook, Volume 31; 2015
11 Power Plant Kemper county
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Notes:

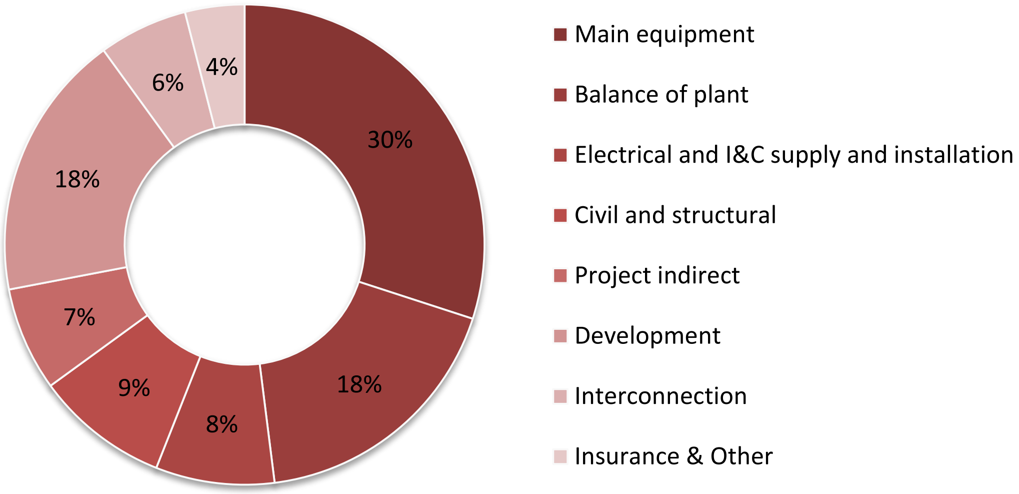
A $=P_{el}/(P_{el}+P_{th})$ in "heat and power mode"
B $=P_{th}/(P_{el}+P_{th})$ in "heat and power mode"
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E $=MW_{el,aux.pwr}/MW_{th}$ in "heat and power mode"
F District heating steam temperature 185 °C; Cb=1.06; Cv=0.79; slightly higher efficiencies estimated, since steam turbine's isentropic efficiency decreases from high to low pressure.
G District heating water temperature 135 °C; Cb=1.14; Cv=0.85
H Design case! District heating water temperature 105 °C; Cb=1.18; Cv=0.88
I District heating water temperature 70 °C; Cb=1.27; Cv=0.94
J Reference location is USA / Germany
K Data is related to a IGCC with condensing steam turbine with extraction at 1.7 bar running in "only electric power mode" (maximum electric power at STG); GT is running at ISO conditions; for financial data using a backpressure steam turbine @ proper backpressure values for district heating reduce values for nominal investment (equipment & installation) by appr. 2%
L Data Correction for different district heating temperatures estimated within error margin
M x… Electrical power generation [100…500 MW_{el}]

6.1.7 Organic Rankine Cycle plants

For CHPPs using Organic Rankine Cycle (ORC) configurations the approach for the calculation of thermal power, which can be used for district heating, is at a temperature level of 105 °C ("Warm / Hot Water") and a reasonable value for the exhaust flue gas stack temperature depending on the fuel of the thermal oil boiler. Heat for the district heating system is recovered in two steps. In the first one heat is used from the ORC process itself (e.g. silicon oil cycle) and in the second one from the flue gas of the thermal oil boiler. The corresponding electrical power is generated by the ORC turbine generator set. ORC plants have a typical thermal power range from 1 – 50 MW.

The major components of ORC CHPPs are the thermal oil boiler with combustion air preheater, flue gas heat recovery section and stack, the ORC cycle including turbine and electrical generator plus corresponding heat exchanger / oil condenser for district heating.

Figure 37: CAPEX breakdown of Organic Rankine Cycle CHPs[10]



6.1.7.1 Biomass fired ORC plants

Future prospects for parameters are mainly based on an ongoing and likely further development on ORC CHPPs. Financial trend is taken from extrapolation of OEM's budget data and literature.

Assumptions for the data in the table below: Biomass (LHV appr. 14 MJ/kg) fired ORC CHPP (appr. 6% O_2 flue gas; flue gas stack temperature 135 °C; two-stage district heat exchanger). Performance values of table below are based on and calculated with performance data from "ORC performance library" and OEM's typical data sheets. Estimated inlet district heating temperature is 60 °C.

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[10] Cost for the district heating connection itself (like net pumps and other auxiliary units) will be in the range of 1%

Table 34: Overview of biomass fired ORC plants

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2
Heat generation capacity	MW_{th}	10 - 50												
Electrical power generation	MW_{el}	1 - 8												
Net electrical efficiency	%	12.8	13	13.5	14	14		12	14	13	16			
degree of fuel utilization accountable to el. Power	%	17.8	18	18	18.5	18.5		16	20	17	21		A	
degree of fuel utilization accountable to district heating	%	82.2	82	82	81.5	81.5		80	84	79	83		B	
Total degree of utilization. nominal load	%	76.7	77	78	79	80		75	80	75	85			
Total degree of utilization. annual average	%	70	70	71	72	73							C, D	
Electricity consumption	%	1.7	1.7	1.6	1.5	1.5		1	2	1	2		E	
Technical lifetime	years	25	25	30	30	30		20	25	25	35			
Steam supply		N/A	N/A	N/A	N/A	N/A		N/A	N/A	N/A	N/A		F	
Hot water		o	o	o	o	o		o	-	o	-		G	
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	o	(o)	o			
Low temperature		o	o	o	o	o		o	+	o	+			
B. Environmental data														5, 6, 7
CO2	g/MJ_{th}	130	130	130	125	125		110	150	90	130			
SO2	g/GJ_{th}	5	5	4	4	3		4	10	4	10			
NOX	g/GJ_{th}	100	95	90	90	85		90	120	80	100			
CH4	g/GJ_{th}	<	<	<	<	<								
N2O	g/GJ_{th}	<	<	<	<	<								
Particles	g/GJ_{th}	5	5	5	5	5		3	12	3	12			
C. Financial data													H	1, 3, 8, 9, 10, 11
Quality of estimation		medium												
Nominal investment	$M€/MW_{el.max}$	4.7	4.7	4.6	4.6	4.5		4	5	3.8	5		I	
- of which equipment	$M€/MW_{el.max}$	3.53	3.53	3.45	3.45	3.38		3.00	3.75	2.85	3.75			
- of which installation	$M€/MW_{el.max}$	1.18	1.18	1.15	1.15	1.13		1.00	1.25	0.95	1.25			
Fixed O&M	$k€/MW_{el.max}/a$	45	44	42	42	40		40	50	35	50			
Variable O&M excl. electricity costs	$€/MWh_{el.max}$	8	8	8	8	8		5	10	5	10			
X. Technology specific data														
Cost function	$M€/MW_{el}$	Invest(x)=$6.65^{-0.25}$											J	

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10 Kraft-Wärme-Kopplung, 4.te Auflage, Springer, Schaumann/Schmitz
11 Budget Offer: BIOS Bioenergiesysteme GmbH

Notes to table above

A $=P_{el}/(P_{el}+P_{th})$ in "heat and power mode"
B $=P_{th}/(P_{el}+P_{th})$ in "heat and power mode"
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E =MWel,aux.pwr/MWth in "heat and power mode"
F Low fuel utilization
G Cb factor approximately independent from district heating temperature. Cb mainly connected to ORC process parameters. In this case: Cb=0.22; Cv=1.0
H Reference location is Central Europe
I Data Correction for different district heating temperatures is insignificant
J x… Electrical power generation [1…8 MW_{el}]

6.1.7.2 Solid waste fired ORC plants

Future prospects for parameters are mainly based on an ongoing and likely further development on ORC CHPPs. Financial trend is taken from extrapolation of OEM’s budget data and literature.

Assumptions for the data in the table below: Solid waste (LHV appr. 13 MJ/kg) fired ORC CHPP (appr. 6% O_2 flue gas; flue gas stack temperature 160 °C; two-stage district heat exchanger). Performance values of table below are based on and calculated with performance data from “ORC performance library” and OEM’s typical data sheets. Estimated inlet district heating temperature is 60 °C.

Table 35: Overview of solid waste fired ORC plants

	Unit	**2015**	**2020**	**2030**	**2040**	**2050**		**Uncertainty (2020)**		**Uncertainty (2050)**			**Note**	**Ref**
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			1, 2 , 4, 10, 11, 13
Heat generation capacity	MW$_{th}$	10 - 50												
Electrical power generation	MW$_{el}$	1 - 8												
Net electrical efficiency	%	14.5	14.5	15	15	15		12	15	13	16			
degree of fuel utilization accountable to el. Power	%	17.8	18	18	18.5	18.5		16	20	17	21		A	
degree of fuel utilization accountable to district heating	%	82.2	82	82	81.5	81.5		80	84	79	83		B	
Total degree of utilization, nominal load	%	87	87	88	88	89		75	90	75	90			
Total degree of utilization, annual average	%	79	79	80	80	81							C, D	
Electricity consumption	%	1.7	1.7	1.6	1.5	1.5		1	2	1	2		E	
Technical lifetime	years	25	25	30	30	30		20	25	25	35			
Steam supply		N/A	N/A	N/A	N/A	N/A							F	
Hot water		o	o	o	o	o		o	-	o	-		G	
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	o	(o)	o			
Low temperature		o	o	o	o	o		o	+	o	+			
B. Environmental data														5, 6, 7, 10, 11, 12
CO2	g/MJ$_{th}$	150	150	145	145	140		130	170	120	160			
SO2	g/GJ$_{th}$	6	6	5	5	4		4	10	4	10			
NOX	g/GJ$_{th}$	120	115	110	110	100		90	150	70	130			
CH4	g/GJ$_{th}$	<	<	<	<	<								
N2O	g/GJ$_{th}$	<	<	<	<	<								
Particles	g/GJ$_{th}$	12	11	10	10	8		5	15	5	15			
C. Financial data													H	1, 3, 8, 9, 10, 14, 15
Quality of estimation		medium												
Nominal investment	M€/MW$_{el,max}$	15.9	15.5	15	15	14		10	20	10	20		I	
- of which equipment	M€/MW$_{el,max}$	9.5	9.3	9.0	9.0	8.4		6	12	6	12			
- of which installation	M€/MW$_{el,max}$	6.4	6.2	6.0	6.0	5.6		4	8	4	8			
Fixed O&M	k€/MW$_{el,max}$/a	160	150	150	140	140		100	200	100	200			
Variable O&M excl. electricity costs	€/MWh$_{el,max}$	8	8	8	8	8		5	10	5	10			
X. Technology specific data														
Cost function	M€/MW$_{el}$	Invest(x)=$22.5^{-0.25}$											J	

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1 Energy Technology Reference Indicator, Projections for 2010-2050
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4 Turboden CHP Units – Typical sizes and Performances
5 Emissionen aus Verbrennungsvorgängen zur Raumwärmeerzeugung, Umweltbundesamt
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15 Budget Offer: BIOS Bioenergiesysteme GmbH

Notes:

A $=P_{el}/(P_{el}+P_{th})$ in "heat and power mode"
B $=P_{th}/(P_{el}+P_{th})$ in "heat and power mode"
C based on planned availability of 8 000 h/a (DH+GEN)
D uncertainty depending on (unplanned) maintenance
E $=MW_{el,aux.pwr/}MW_{th}$ in "heat and power mode"
F Low fuel utilization
G Cb factor approximately independent from district heating temperature. Cb mainly connected to ORC process parameters. In this case: Cb=0.22; Cv=1.0
H Reference location is Central Europe
I Data Correction for different district heating temperatures is insignificant
J x… Electrical power generation [1…8 MW_{th}]

6.1.8 References

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Books/Brochures

- Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Technical Report, ISBN: 978-87-7844-931-3. Danish Energy Agency and Energinet.dk, 2012 (https://www.energinet.dk/SiteCollectionDocuments/Danske%20dokumenter/Forskning/Technology_data_for_energy_plants.pdf)
- „Projektmanagement im Energiebereich", Verlag: Springer Gabler; Lau/Dechange/Flegel; ISBN 978-3-658-00267-1; 2013
- Gas Turbine World 2014 – 2015 Handbook, Volume 31; 2015
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- Forced Draught Burner Handbook (http://www.cfquadrant.ie/wp-content/uploads/2015/02/Riello-Burner-Handbook.pdf)
- Arbeitsgemeinschaft Erneuerbare Energie Dachverband (http://www.aee.at/aee/index.php?option=com_content&view=article&id=525&Itemid=113)

- County Meath, Ireland; B&W Volund; http://www.volund.dk/News/2014/01/Newsletter/Ireland_switches_on_waste-powered_electricity
- Wirtschaftlich effiziente Biomasse-Heizkraftwerke, Rolf Michler (http://www.enpros.de/de/download/Media/EPG_WirteffBiomHKW_413001EPS000DF001_00ArtBiom131016.pdf?m=1409315893
- Biomasse Kraftwerk Güssing; Repotec http://www.repotec.at/index.php/ws-biomassekraftwerk-guessing.html
- Power Plant Kemper county http://www.power-technology.com/projects/kemper-county-integrated-gasification-combined-cycle-igcc-power-plant-mississippi/
- RWE IGCC / CCS Power Plant http://www.rwe.com/web/cms/en/2688/rwe/innovation/power-generation/fossil-fired-power-plants/igcc-ccs-power-plant/
- Kraftwerke mit kohle Vergasung; BINE Informationsdienst http://www.bine.info/fileadmin/content/Publikationen/Projekt-Infos/2006/Projekt-Info_09-2006/projekt_0906internet-x.pdf

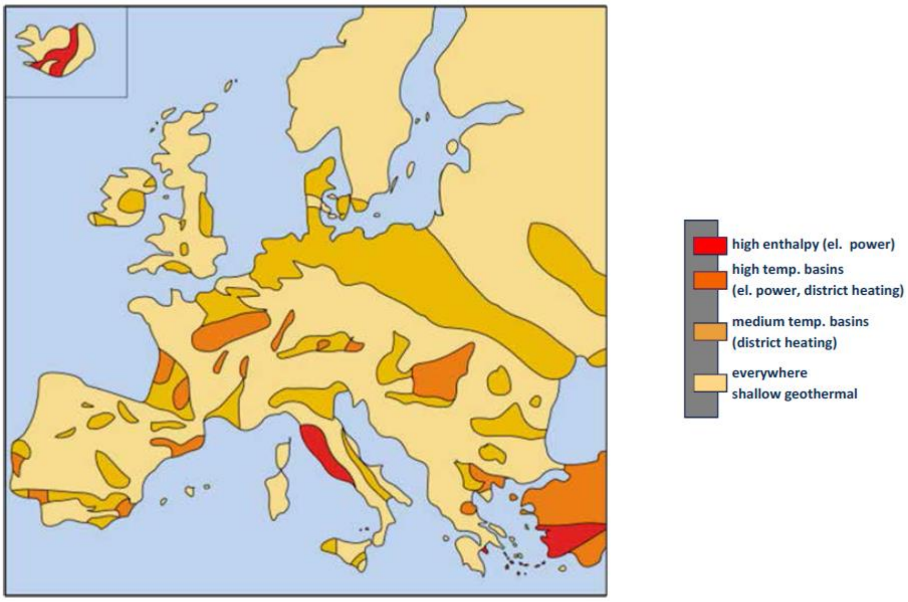
6.2 Geothermal power plants

The functional principle of a geothermal power plant is similar to that of any other thermal power plant: a turbine is operated by steam and electricity is produced through a generator. The exact process depends on the nature of the geothermal power plant. All types differ slightly in their operation, but normally all types of power stations use an injection and a production well for electricity production.

As fields of pure natural steam are rather rare, most geothermal plants are based on a mixture of steam and hot water requiring single-flash (some use double-flash) systems to separate the hot water. In general, high-enthalpy geothermal fields are only available in areas with volcanic activity, whereas the rest of the fields are low- or medium-enthalpy resources. Geothermal power generation is mainly based on steam/flash and binary plants.

The figure below gives an overview of the geothermal resources in Europe. According to the picture, Iceland, Tuscany and Turkey has the best geothermal potentials in Europe, where both heat and electricity generation is possible. But also other regions have the potential for cogeneration, however, with lower efficiency.

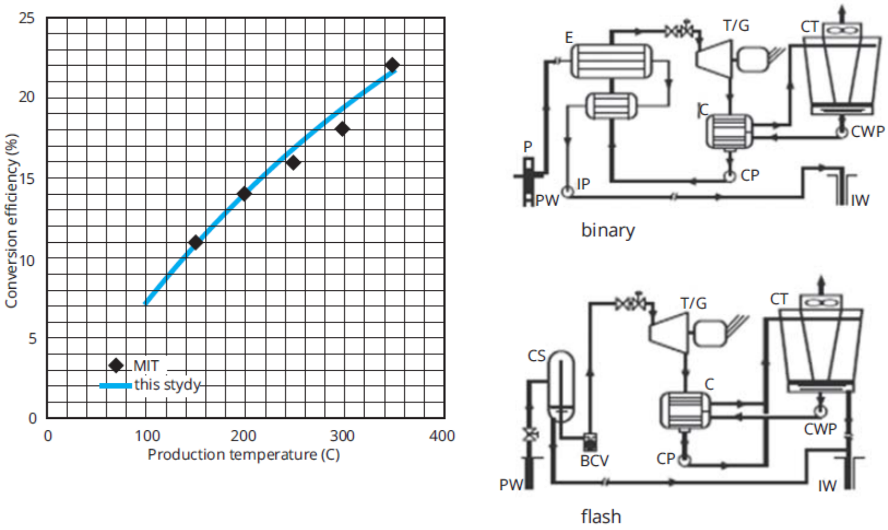
Figure 38: Geothermal resources in Europe.



Source: EGEC - European Geothermal Energy Council

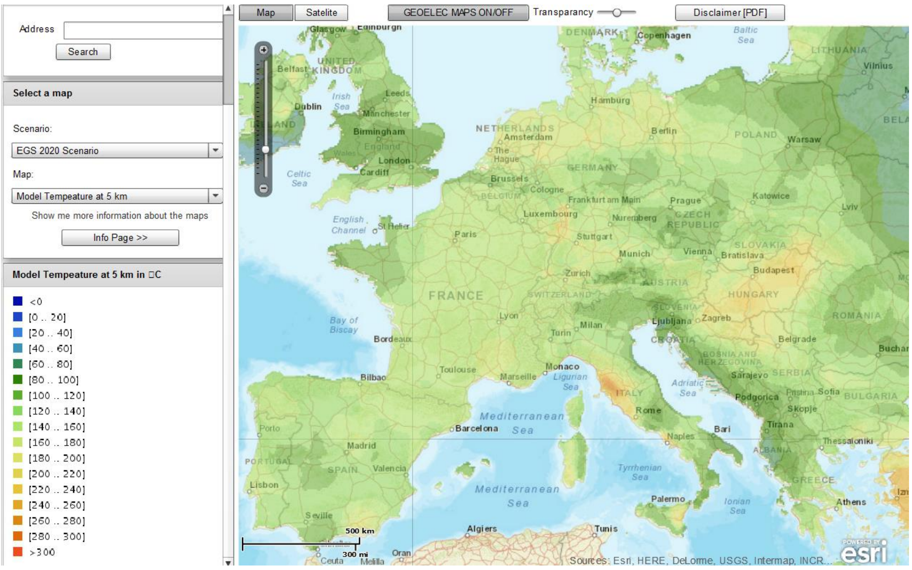
With the following figure, the electrical efficiency could be estimated in dependency on the production temperature. The curve fits both for binary and flash steam plants. Using the next figure, respectively the internet link, modelled temperatures in different depths could be identified. Knowing the depth, in which the needed temperature could be found, the drilling costs could be calculated. Each technology sheet provides a formula therefore.

Figure 39: Practically achieved conversion efficiencies of various geothermal production installations (left), including both binary and flash systems (right) (after Tester et al., 2006)



Source: Towards more geothermal electricity generation in Europe; EGEC, 2013

Figure 40: Modelled temperature at 5 km in °C



Scenario: EGS 2020 Scenario
Map: Model Tempeature at 5 km

Source: http://www.thermogis.nl/geoelec/ThermoGIS_GEOELEC.html

6.2.1 Flash plants

Geothermal flash steam plants operate with large hydrothermal reservoirs at high temperature (i.e. over 150 °C). In Europe such reservoirs can be found in Tuscany (Italy) and Iceland. Unfortunately, it is very unlikely that new large geothermal reservoirs like these will be discovered in Europe. Therefore new projects need to be adapted to smaller and cooler resource conditions.

Geothermal flash plants are used to extract energy from high-enthalpy geothermal reservoirs. Water with high temperature at high pressure is brought to surface, where it enters a low pressure chamber and steam is obtained from a separation – the flashing - process. Then the steam is directed to a turbine, which spins to generate electrical power. After passing the turbine, the steam is condensated and normally (except for condensate evaporated in a wet cooling system) injected back to the underground.

The high temperature, water at high pressure is brought to surface, where it is enters a low pressure chamber and "flashes" into steam. The pressure created by this steam is channelled through a turbine, which spins to generate electrical power. Once the steam has exited the turbine, it is either released into the atmosphere as water vapour, or it cools back into liquid water and is injected back underground.

The CAPEX breakdown structure listed below differs from the definition of main equipment and balance of plant (BOP) to the others. For this technology, the drilling effort is taken into account with the balance of plant (BOP) in order to show the significant influence of the drilling on the total investment. Note: The presented cost distribution can vary widely from one project to another. Especially estimating the borehole costs, large uncertainties exist due to the limited availability of drilling rigs, changing feedstock prices (e.g. steel), unforeseen technological problems and on-site conditions.

Main equipment: Energy conversion plant with its main components like water/steam supply system, flashing/separation units, turbines, condensate treatment system, heat exchangers, pumps, filters, etc.

Balance of plant: Borehole costs are dominating the overall investment costs and consists of seismics / preparatory arrangements, set up and recultivation of the drilling site, drilling lease (including personnel and energy costs), costs for drilling bits and mud (including the disposal of mud and cuttings) as well as logging and borehole completion and steam gathering system.

Figure 41: CAPEX breakdown of geothermal flash CHP plants

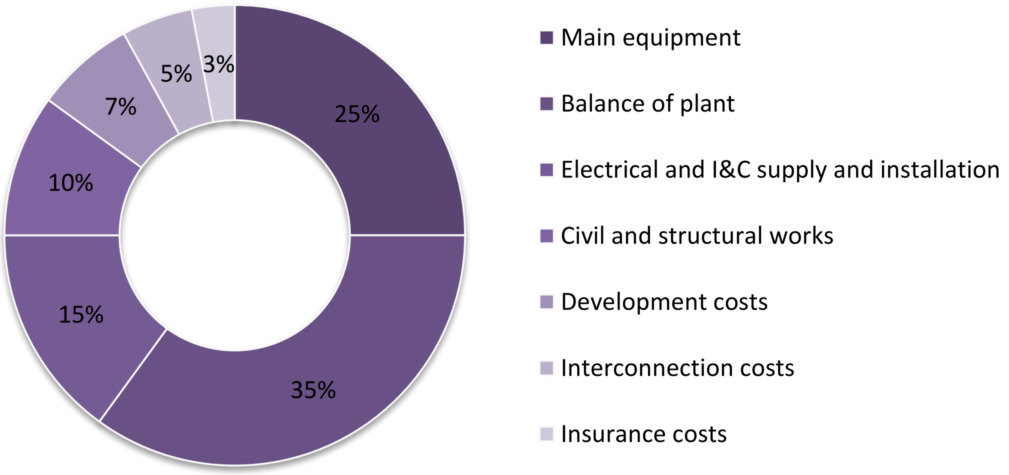


Table 36: Overview of geothermal flash CHP plants

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
El. generation capacity	MW_{el}	10 - 50						10	70	10	100		A	1, 2, 3
El. efficiency, nominal load	%	12 - 20						10	23	13	25		B	4
Electricity consumption	%/MW_{th}	10						5	15	5	15		C	1
Technical lifetime	years	30	30	30	30	30		25	>30	25	>30		D	5, 6
Steam supply		--	--	--	--	--		-	--	-	--		E	
Hot water		o	o	o	o	o		-	o	-	o			
Warm water		(o)	(o)	(o)	(o)	(o)		(o)	o	(o)	o			
Low temperature		+	+	+	+	+		(+)	++	o	++			
B. Environmental data														
CO2	g/MJ_{th}	7.6	7.6	7.6	7.6	7.6							F	7, 8
SO2	g/GJ_{th}	3.3	3.3	3.3	3.3	3.3								8
NOX	g/GJ_{th}	24	24	24	24	24								8
CH4	g/GJ_{th}	11.6	11.6	11.6	11.6	11.6								8
N2O	g/GJ_{th}	7.3	7.3	7.3	7.3	7.3								8
Particles	g/GJ_{th}	1.4	1.4	1.4	1.4	1.4								8
C. Financial data														
Quality of CAPEX estimation		medium												
Learning rate	%	5 - 15											G	9, 10
Nominal investment	M€/MW_{el}	5.2	5.1	4.8	4.6	4.2		3.5	7.0	2.5	5.0		H	1, 5, 11, 12, 13, 14, 15
- of which equipment	M€/MW_{el}	1.8	1.8	1.7	1.6	1.5		1.5	2.3	1.3	1.9		I	12, 16
- of which installation	M€/MW_{el}	3.4	3.3	3.1	3.0	2.7		2.8	3.6	2.3	2.9			12, 16
Fixed O&M	k€/MW_{el}/a	75	70	70	65	65		60	85	55	75		J	1, 5, 6, 13, 15, 17
Variable O&M excl. electricity costs	€/MWh_{el}	N/A	N/A	N/A	N/A	N/A								
X. Technology specific data														
Cost function (estimation)	M€/MW_{th}	Invest(x)=$6.73x^{-0.12}$											K	6, 12, 18
Cost function drilling (estimation)	€/m	$C_{Drilling}$(Depth) = 0.152 * (Depth) + 785											L	19, 20
Construction time	years	6	6	6	6	6		5	7	5	7		M	21
Capacity factor	%	95	95	95	95	95		90	97	90	98		N	6, 22
Production rate	l/s	50 - 150											O	1
Typical drilling depth	km	7	7	7	8	10							P	21
Reservoir temperature	°C	> 150											Q	8, 21
Average daily drilling capacity	m/day	40						30 - 50					R	20

References:

1 Energy Technology Reference Indicator projections for 2010-2050; JRC, 2014
2 Renewable Energy in Europe - Markets, Trends and Technologies; EREC, 2010
3 Stand und Perspektiven geothermischer Stromerzeugung; H. Spliethoff, May 2012
4 Level of typical efficiencies for electricity generation of geothermal plants; R. Bertani, June 2016
5 Geothermal Handbook: Planning and Financing Power Generation; ESMAP, 2012
6 Geothermal Energy Status Report - Technology, market and economic aspects of geothermal energy in Europe; JRC, 2015
7 Geothermal Power Plants: Principles, Applications, Case Studies and Environmental Impact; R. DiPippo, 2012
8 Renewable Energy Cost of Generation Update; KEMA, August 2009
9 Annual Energy Outlook 2012 with Projections to 2035; EIA, June 2012
10 Modelling Technology Learning for Electricity Supply Technologies; E. Rubin et al., May 2013
11 Renewables for Heating and Cooling - Untapped Potential; OECD/IEA, 2007
12 Geothermal Investment Guide; GEOELEC, 2013
13 Current and Prospective Costs of Electricity Generation until 2050; DIW, 2013
14 Cost and Performance Data for Power Generation technologies; NREL, 2012
15 Financing Geothermal Energy; EGEC, July 2013
16 Geothermal Power: Issues, Technologies, and Opportunities for Research, Development, Demonstration, and Deployment; EPRI, February 2010
17 Factors Affecting Costs of Geothermal Power Development; Geothermal Energy Association, August 2005
18 Renewable Energy Systems; M. Kaltschmitt et al., 2013 © Springer Science+Business Media New York
19 New Geothermal Site Identification and Qualification; GeothermEx, April 2004
20 Enhanced Geothermal Systems (EGS) Well Construction Technology Evaluation Report; Sandia Report, December 2008
21 Towards more Geothermal Electricity Generation in Europe; GEOELEC, 2013
22 Power Technologies Energy Data Book (Fourth Edition); NREL, August 2006

Notes:

A Total plant capacities range from 10 to 50 MW, with most at approximately 31 MW_{el}.

B The lower value represent a reservoir temperature of 150 °C and the upper 300 °C. Note: In comparison to other energy technologies, geothermal power plants have lower electricity efficiency rates (is largely determined by the reservoir temperature) owing to relatively low temperatures of the geothermal fluids. The overall efficiency is greatly increased by adding heat exchangers and producing hot water since the conversion factor in a heat exchanger is far greater than converting heat to electricity (Ref. 7).

C The electrical consumption through pumps and auxiliary systems could be assumed with 10 % (including condensing and cooling system) of the geothermal power.

D Drillings have a long life time period. Individual components must be replaced earlier due to the corrosive properties of the brine.

E Normally the heat extraction from flash plants is taken from the separator. That means, the heat extraction has no influence on the electricity efficiency but at the same time increasing the total efficiency. However, steam extraction significantly influence the plant efficiency.

F Unlike many renewable technologies, flash geothermal plants produce emissions.

G The learning rates are expected to be relatively modest, as the technology is far developed. Indeed drillings could have the biggest cost reduction potential. On the one hand through faster drilling methods and on the other hand through better exploration (further developed seismic methods could increase the success rate and additionally decrease risk and insurance costs).

H The depth of drilling and the local geological conditions naturally have a high influence on the total investment costs of geothermal power plants. That is why, investment costs have a big bandwidth across different studies (Ref. 13 gives an overview of different studies and each listed costs). Note: Drilling represents 30 - 50 % of the cost of a hydrothermal geothermal electricity project and more than half of the total cost of Enhanced Geothermal System (EGS). The cost reduction is

	mainly assumed due to better forecasting (reducing the risk and insurance costs) and drilling methods.
I	The installation effort on-site consumes high effort and is dominated by the drilling work.
J	The operation and maintenance (O&M) costs increase significantly when dealing with high mineral content brine resources.
K	Cost function is based on own calculations (GEOELEC Tool) and modified under consideration of project information and given references. x…Heat generation capacity.
L	The linearized cost function for drilling is based on the given function of Ref. 19 and data of Ref. 20. The function can be seen as valid in the range of 1 000 - 6 000 m depth. In general, the cost could be estimated with an average value of EUR 1 100/m (1 000 - 3 000 m depth) and EUR 1 500/m (3 000 - 6 000 m depth). The lower borderline costs could be assumed with 1 000 €/m. Excessively higher costs (> EUR 2 500/m) could occur through difficult circumstances. Note: The original formula is described with a polynomial function based on realized drillings with an R-squared value for the curve of 0.558, which indicates that a variance in drilling cost has to be accepted. Due to simplifications, the function was linearized and costs converted into EUR/m (exchange rate: 1 USD ≙ 0,877 EUR).
M	Based on experience, it takes about 5-7 years to bring a geothermal power plant online. The project timeline could be roughly described with: 2 years for exploration & test drilling, 2 years for drilling and up to 3 years for engineering & construction.
N	Due to the high capital intensity given by high drilling costs, geothermal energy plants should be operated as basic load units in order to achieve high full load hours and thus reduce production costs.
O	Higher production rates leads to higher pumping effort which decreases the system efficiency.
P	The maximum drilling depth that is economically feasible with today's technology is 7 km and could be 10 km in 2050.
Q	In general, a flash plant could be economically feasible if the production wells deliver more than 150 °C. The exploitation of hydrothermal resources down to 3-4 km depth is a mature commercial technology where temperatures above 180 °C could be reached. Petrothermal resources could be exploited with the quite new technology EGS from 3-6 km depth, while supercritical plants (T>350°C) from 5-10 km depth will be a future technology.
R	The value is based on a 6 km deep well which could be drilled within approx. 140 days.

6.2.2 Binary plants

Binary plants, also known as Organic Rankine Cycle (ORC) or Kalina Cycle, usually are operating with temperatures in the range from 100 to 180 °C. Special configurations (working fluid) may allow power production from as low temperatures as 80 °C. Binary plants utilize a secondary working fluid, usually an organic fluid (typically n-pentane) with lower boiling point and high vapour pressure at low temperatures as compared to steam. The hot geothermal water is brought to surface from the reservoir and transfers the heat through heat exchangers to the working fluid. After cooling down, the geothermal water is re-injected. Due to the specific thermodynamic properties the working fluid already vaporizes with less geothermal heat. The vapour of the working fluid drives a turbine, then is cooled down and condensed, and the cycle repeats again. The uniqueness of a binary system is that it operates with two closed-loops (hence binary) and neither the geothermal water nor the working fluids are exposed to the environment. That means no emissions occur in a binary geothermal cycle.

The CAPEX breakdown structure listed below differs from the definition of main equipment and balance of plant (BOP) to the others. For this technology, the drilling effort is taken into account with the balance of plant (BOP) in order to show the significant influence of the drilling on the total investment. Note: The presented cost distribution can vary widely from one project to another. Especially estimating the borehole costs, large uncertainties exist due to the limited availability of drilling rigs, changing feedstock prices (e.g. steel), unforeseen technological problems and on-site conditions.

Main equipment: Energy conversion plant with its main components like working fluid circuit, working fluid itself (silicone oil, refrigerant or other gases), expansion machines (turbine, screw expander, steam motor / reciprocating piston expander), heat exchangers, pumps, filters, etc.

Balance of plant: Borehole costs are dominating the overall investment costs and consists of seismics / preparatory arrangements, set up and recultivation of the drilling site, drilling lease (including personnel and energy costs), costs for drilling bits and mud (including the disposal of mud and cuttings) as well as logging and borehole completion and thermal water cycle.

Figure 42: CAPEX breakdown of geothermal binary CHP plants

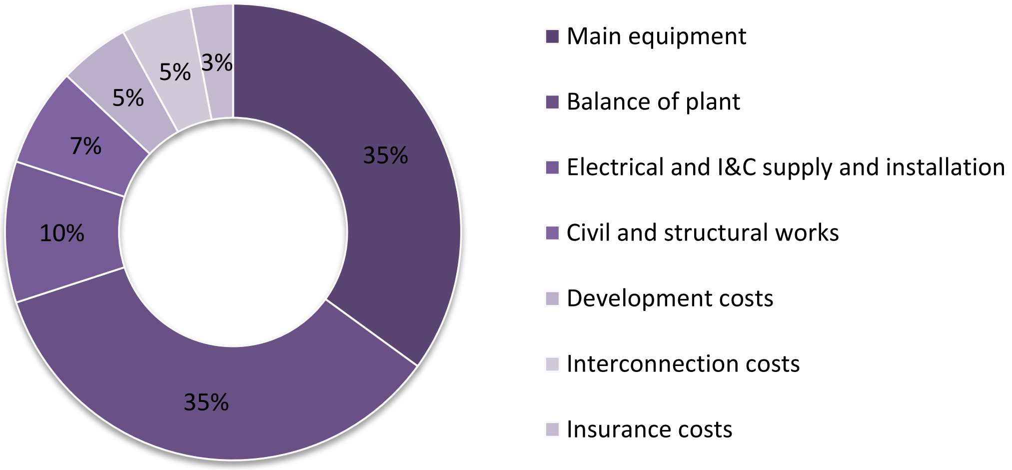


Table 37: Overview of geothermal binary CHP plants

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
El. generation capacity	MW$_{el}$	1 - 30						<1	50	<1	75		A	1, 2, 3
El. efficiency, nominal load	%	7 - 14						5	15	7	16		B	4, 5
Electricity consumption	%/MW$_{th}$	3						2	5	2	5		C	1, 5
Technical lifetime	years	30	30	30	30	30		25	>30	25	>30		D	6, 7
Steam supply		N/A	N/A	N/A	N/A	N/A							E	
Hot water		N/A	N/A	N/A	N/A	N/A								
Warm water		--	--	--	--	--		-	--	-	--		F	
Low temperature		(o)	(o)	(o)	(o)	(o)		(o)	(+)	(o)	+			
B. Environmental data														
CO2	g/MJ$_{th}$	0	0	0	0	0							G	8, 9
SO2	g/GJ$_{th}$	0	0	0	0	0								8, 9
NOX	g/GJ$_{th}$	0	0	0	0	0								8, 9
H2S	g/GJ$_{th}$	0	0	0	0	0								8, 9
CO2	g/GJ$_{th}$	0	0	0	0	0								8, 9
VOC	g/GJ$_{th}$	0	0	0	0	0								8, 9
C. Financial data														
Quality of CAPEX estimation		medium												
Learning rate	%	5 - 15											H	10, 11
Nominal investment	M€/MW$_{el}$	7.0	6.6	6.2	5.9	5.6		6.0	8.0	5.0	6.0		I	1, 5, 12, 13, 14, 15, 16
- of which equipment	M€/MW$_{el}$	2.9	2.7	2.5	2.4	2.3		2.0	3.3	1.7	2.8		J	13, 17
- of which installation	M€/MW$_{el}$	4.1	3.9	3.7	3.5	3.3		3.3	4.6	2.8	3.9			13, 17
Fixed O&M	k€/MW$_{el}$/a	150	145	143	142	140		120	180	110	170		K	1, 5, 7, 14, 16, 18, 19
Variable O&M excl. electricity costs	€/MWh$_{el}$	N/A	N/A	N/A	N/A	N/A								
X. Technology specific data														
Cost function (estimation)	M€/MW$_{th}$	Invest(x)=12.15x$^{-0.24}$											L	7, 13, 20
Cost function drilling (estimation)	€/m	$C_{Drilling}$(Depth) = 0.152 * Depth (m) + 785											M	21, 22
Construction time	years	6	6	6	6	6		5	7	5	7		N	23
Capacity factor	%	95	95	95	95	95		90	97	90	98		O	7, 24
Production rate	l/s	50 - 150											P	1
Maximum depth	km	7	7	7	8	10							Q	23
Reservoir temperature	°C	> 80											R	11, 17
Average daily drilling capacity	m/day	40						30 - 50					S	22

References:

1 Energy Technology Reference Indicator projections for 2010-2050; JRC, 2014
2 Renewable Energy in Europe - Markets, Trends and Technologies; EREC, 2010
3 Stand und Perspektiven geothermischer Stromerzeugung; H. Spliethoff, May 2012
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5 Input from ORC manufacturers; 2017
6 Geothermal Handbook: Planning and Financing Power Generation; ESMAP, 2012
7 Geothermal Energy Status Report - Technology, market and economic aspects of geothermal energy in Europe; JRC, 2015
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10 Annual Energy Outlook 2012 with Projections to 2035; EIA, June 2012
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18 Factors Affecting Costs of Geothermal Power Development; Geothermal Energy Association, August 2005
19 Power Plants: Characteristics and Costs; S. Kaplan, November 2008
20 Renewable Energy Systems; M. Kaltschmitt et al., 2013 © Springer Science+Business Media New York
21 New Geothermal Site Identification and Qualification; GeothermEx, April 2004
22 Enhanced Geothermal Systems (EGS) Well Construction Technology Evaluation Report; Sandia Report, December 2008
23 Towards more Geothermal Electricity Generation in Europe; GEOELEC, 2013
24 Power Technologies Energy Data Book (Fourth Edition); NREL, August 2006

Notes:

A Binary plant capacities range from 1 to 30 MW, with most at approximately 4 MW_{el}. ORC units are typically produced in very small sizes (0.1 - 5 MW) and container module units allow modular design. Due to high specific investment costs, the electrical power should be greater than 500 kW and water temperatures higher than 100 - 120 °C.

B The lower value represents a reservoir temperature of 80 °C and the upper 180 °C. Note: In comparison to other energy technologies, geothermal power plants have lower electricity efficiency rates (is largely determined by the reservoir temperature) owing to relatively low temperatures of the geothermal fluids. The overall efficiency is greatly increased by adding heat exchangers and producing hot water since the conversion factor in a heat exchanger is far greater than converting heat to electricity (Ref. 8).

C The electrical consumption through pumps and auxiliary systems could be assumed with 3 % of the geothermal power.

D Drillings have a long life time period. Individual components must be replaced earlier due to the corrosive properties of the brine or special requirements of the binary system.

E Binary plants are used for CHP applications driven by low temperatures. Therefore, high temperature applications for district heating should be avoided as the CHP unit will be shut down and the geothermal energy will be used directly.

F High supply temperatures affect the (already low) electrical efficiency and could jeopardize the economic viability of a geothermal plant. That is why, low temperature applications should be preferred.

G Closed loop binary plants emit no gaseous emissions during operation.

H The learning rates are expected to be relatively modest. Indeed drillings could have the biggest cost reduction potential. On the one hand through faster drilling methods and on the other hand through better exploration (further developed seismic methods could increase the success rate and additionally decrease risk and insurance costs).

I Binary plants are more expensive than flash plants due to the ORC unit. The specific investment cost of an ORC unit could be counted with around MEUR 1.5/MW_{el}. The depth of drilling and the local geological conditions naturally have a high influence on the total investment costs of geothermal power plants. That is why, investment costs have a big bandwidth across different studies (Ref. 14 gives an overview of different studies and each listed costs). Drilling represents 30 - 50 % of the cost of a hydrothermal geothermal electricity project and more than half of the total cost of Enhanced Geothermal System (EGS). The cost reduction is mainly assumed due to better forecasting (reducing the risk and insurance costs) and drilling methods.

J Binary plants consume a little bit less installation effort in comparison to flash plants (e.g. the ORC plant could be delivered prefabricated).

K In comparison to flash plants, binary plants consume higher O&M costs. Some ORC manufacturer offers O&M packages for some thousands Euro per plant and year. Note: The operation and maintenance (O&M) costs increase significantly when dealing with high mineral content brine resources.

L Cost function is based on own calculations (GEOELEC Tool) and modified under consideration of project information and given references. x…Heat generation capacity.

M The linearized cost function for drilling is based on the given function of Ref. 21 and data of Ref. 22. The function can be seen as valid in the range of 1 000 - 6 000 m depth. In general, the cost could be estimated with an average value of EUR 1 100/m (1 000 - 3 000 m depth) and EUR 1 500/m (3 000 - 6 000 m depth). The lower borderline costs could be assumed with 1 000 €/m. Excessively higher costs (> EUR 2 500/m) could occur through difficult circumstances. Note: The original formula is described with a polynomial function based on realized drillings with an R-squared value for the curve of 0.558, which indicates that a variance in drilling cost has to be accepted. Due to simplifications, the function was linearized and costs converted into EUR/m (exchange rate: 1 USD ≙ 0,877 EUR).

N Based on experience, it takes about 5-7 years to bring a geothermal power plant online. The project timeline could be roughly described with: 2 years for exploration & test drilling, 2 years for drilling and up to 3 years for engineering & construction.

O Due to the high capital intensity given by high drilling costs, geothermal energy plants should be operated as basic load units in order to achieve high full load hours and thus reduce production costs.

P Higher production rates leads to higher pumping effort which decreases the system efficiency.

Q The maximum drilling depth that is economically feasible with today's technology is 7 km and will be 10 km in 2050.

R In general, a geothermal binary plant could be economically feasible if the production wells deliver more than 100 °C. The exploitation of hydrothermal resources down to 3-4 km depth is a mature commercial technology where temperatures above 180 °C could be reached. Petrothermal resources could be exploited with the quite new technology EGS from 3-6 km depth but with higher development costs.

S The value is based on a 6 km deep well which could be drilled within approx. 140 days.

6.3 Fuel Cells

6.3.1 Polymer electrolyte membrane fuel cells

The proton exchange membrane fuel cell (PEMFC) exist in low (~ 80 °C) and high temperature (~ 180 - 200 °C) varieties, and use proton conducting ionomer (ionic polymer) electrolytes. PEMFC systems currently achieve relatively long lifetimes with good tolerance to thermal cycling, but face challenges in long-term cost reduction. Electrical efficiencies in the range of 30 - 40 % and total (heat + power) efficiencies up to 90 % in CHP mode could be reached. A stationary heat supply application with a temperature level up to 80 °C is possible, wherein heat and electricity could be generated in approximately equal proportions.

Most PEMFC systems rely on platinum catalysts to ensure adequate reaction kinetics and thus power density. These materials are expensive and effective substitutes are scarce. However, good progress has been made to reduce platinum loadings. As the reactions take place at relatively low temperatures (60 - 120 °C), very pure hydrogen is required to fuel the stack, and certain impurities in the fuel can cause rapid degradation in performance. Especially the low tolerance to carbon monoxide (CO) and sulphur is a problem. Ongoing R&D is to increase the CO tolerance of the membranes. Another approach is the development of high-temperature PEMFCs operating at up to 200 °C. Due to the higher temperatures, the impact of some of these issues can be reduced but not removed. Moreover, a suitable ionomer for this temperature range is presently also problematic.

Key challenges for R&D activities are design simplification and efficiency improvement of the fuel processing stages, which will improve the system performance by reducing parasitic loads and reducing thermal losses.

At the moment not so many PEMFC applications in DH systems exist. Especially in Europe there are just only few plants, mostly with demonstration character. That means the given CAPEX breakdown structure could vary, particular when the costs for the fuel cells decrease with higher market penetration.

Figure 43: CAPEX breakdown of polymer electrolyte membrane fuel cells

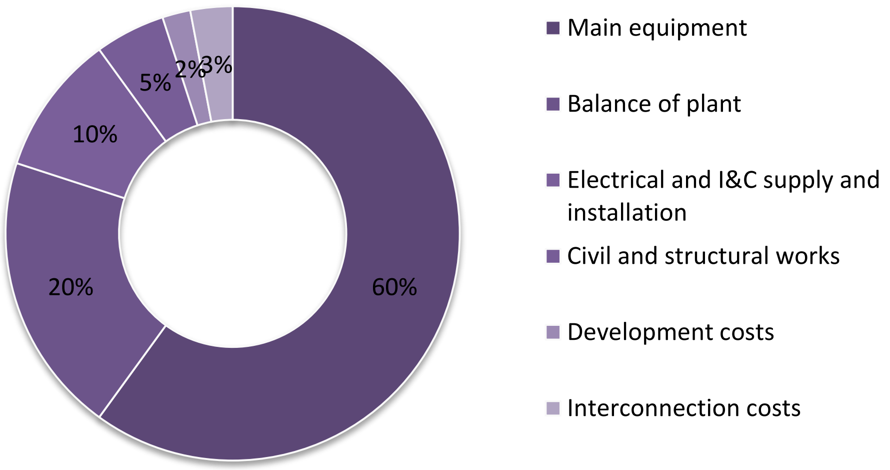

Table 38: Overview of polymer electrolyte membrane fuel cells

	Unit	**2015**	**2020**	**2030**	**2040**	**2050**		**Uncertainty (2020)**		**Uncertainty (2050)**			**Note**	**Ref**
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Typical capacity size	MW$_{el}$	0.001 - 0.1											A	1
Electrical efficiency @peak electrical load	%	36	37	38	39	39							B	2
25 % load		32	33	33	33	34								3
Thermal efficiency @peak thermal load	%	52	52	52	52	52								2
Electricity consumption	%/MW$_{th}$	1	1	1	1	1		0.8	1.5	0.7	1.3		C	4
Technical lifetime	years	5	6	10	12	15		3	8	10	20		D	5, 6
Steam supply		N/A	N/A	N/A	N/A	N/A							E	
Hot water		N/A	N/A	N/A	N/A	N/A								
Warm water		--	--	--	--	--		--	--	--	-			
Low temperature		(o)	(o)	(o)	(o)	(o)		-	(+)	-	+		F	
B. Environmental data (fuel: hydrogen)														
CO2	g/MJ$_{th}$	0	0	0	0	0							G	5
SO2	g/GJ$_{th}$	0	0	0	0	0								5
NOX	g/GJ$_{th}$	0	0	0	0	0								5
CH4	g/GJ$_{th}$	0	0	0	0	0								5
N2O	g/GJ$_{th}$	0	0	0	0	0								5
Particles	g/GJ$_{th}$	0	0	0	0	0								5
C. Financial data														
Quality of CAPEX estimation		Low												
Learning rate	%	15 - 18											H	7
Nominal investment	M€/MW$_{el}$	45	18	13	10	5		15	20	5	10		I	2, 6, 7, 8
- of which equipment	M€/MW$_{el}$	32	13	9	7	3		11	14	3	4			9, 10, 11, 12
- of which installation	M€/MW$_{el}$	13	5	4	3	30		4	7	1	2			9, 10, 11, 12
Fixed O&M	k€/MW$_{el}$/a	N/A	N/A	N/A	N/A	N/A							J	9
Variable O&M excl. el. and fuel costs	€/MWh$_{el}$	100	80	60	40	20							K	2, 3, 9, 13
X. Technology specific data														
Heat to power ratio	1	1.4	1.4	1.4	1.3	1.3								2
Fuel to cell		Hydrogen											L	5
Working temperature	°C	70	80	80 - 100	90 - 140	100 - 180							M	1, 3, 14
Construction time	months	8	6	5	4	4		5	8	3	5			13
Start time	min	20	15	10	8	5							N	15
Availability	%	98	99	99	99	99								15
Degradation with cycling	%/1 000 h	<0.3	<0.2	<0.1	<0.1	<0.05								15

References:

1 Fuel Cells for Stationary Applications; IEA ETSAP, January 2013
2 Energy Technology Reference Indicator projections for 2010-2050; JRC, 2014
3 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Energinet.dk, May 2012
4 Stationäre Brennstoffzellen (Projektergebnisse der ARGE-Brennstoffzelle, Advanced Fuel Cell Workshop); H. Wilk, September 2006
5 FUEL CELLS - Impact and consequences of Fuel Cells technology on sustainable development; D. Oertel and T. Fleischer, March 2003
6 Technology Roadmap - Hydrogen and Fuel Cells; OECD/IEA, 2015
7 The cost of domestic fuel cell micro-CHP systems; Staffell and Green, 2012
8 Best available technologies for the heat and cooling market in the European Union; JRC, 2012
9 Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants; U.S. Energy Information Administration (EIA), April 2013
10 Technology Data for Energy Plants - Individual Heating Plants and Energy Transport; Energinet.dk, May 2012
11 Fuel Cells (Presentation); E. Allen, 2012
12 Fuel Cells - Selected Entries from the Encyclopedia of Sustainability Science and Technology; K.-D. Kreuer, 2013 © Springer Science+Business Media New York
13 Levelized Cost of Energy Analysis; Lazard, 2014
14 The role of hydrogen and fuel cells in providing affordable, secure low-carbon heat; H2FC SUPERGEN, 2014
15 1–10 kW Stationary Combined Heat and Power Systems Status and Technical Potential; NREL, May 2010

Notes:

A Fuel cells are modular in nature. Therefore, systems can be connected together to create larger installations. This type of FC is primarily focused on smaller stationary applications.
B Based on lower heating value (LHV).
C Measured operational data from the PEMFC heating device in Dietachdorf, Austria.
D Lifetime is calculated with 8 000 operation hours per year. End of operating time is defined until > 20 % net power degradation is reached.
E Temperature resistance of the membrane is a limiting factor.
F Low temperature applications are suitable for the use of PEMFC technology. Such developments were also carried out by heating equipment manufacturers (e.g. Vaillant, Viessmann, etc.) and also tested in the field.
G Emissions based on fuel consumption (that means if a fossil fuel is reformed to hydrogen, the emissions from reforming process have to be considered). No emissions occur if the fuel cell is operated on pure hydrogen by electrolysis.
H Ref. 13 notes that the prices offered by several manufacturers are falling by 15 - 18 % for each doubling of cumulative systems shipped.
I Fuel treatment (e.g. methane reformer / electrolyser) is included but no building. Most PEMFC systems are based on platinum catalysts (ensures adequate reaction kinetics and thus power density) which makes this FC-type expensive (effective substitutes are scarce).
J According to Ref. 9, most FC operators do not treat O&M on a fixed basis, and consequently, all O&M expenses are shown on a variable basis.
K Mainly caused by service and maintenance (e.g. change of filters, fuel cell stacks, etc.). Recommended service is comprised of routine short interval inspections/adjustments and periodic replacement of filters (projected at intervals of 2 000 to 4 000 hours).
L This technology needs hydrogen as fuel as internal reforming is not possible. If another primary fuel should be used, it needs to be reformed into hydrogen in an external reformer in advance. However, a variant of the LT PEM can operate directly on diluted methanol. Notice: Especially LT PEMFCs are sensitive to carbon monoxide in the fuel gas. LT PEMFC only operates on very clean hydrogen (CO < 50 - 100 ppm). HT PEMFC is more tolerant (CO of appr. 1 % is accepted) (Ref. 3).
M PEMFC systems exist in low (LT PEM: up to 80 °C) and high temperature (HT PEM: up to 200 °C) varieties, and use proton conducting ionomer (ionic polymer) electrolytes in modern cells (Ref. 1).
N Start-up time from 20 °C ambient temperature. Transient response (10 - 90 % rated power) will be lower than 1 minute.

6.3.2 Solid oxide fuel cells

The solid oxide fuel cell (SOFC) is a high-temperature fuel cell with high operating temperatures of 650 – 1 000 °C. The electrolyte of this cell type consists of a solid ceramic material, which is capable of conducting oxygen ions, but is nevertheless insulating for electrons. Many solid oxide fuel cell projects are still under development, but some are already on the market. The SOFC application is particularly interesting for the power-to-gas process, which has only relatively low efficiencies with conventional technology. With reversibly operated solid oxide fuel cells, on the other hand, current-to-current efficiencies of up to about 70 % are possible, whereby the efficiency is roughly comparable to pumped-storage power plants.

Electrodes, cathode and anode are mounted on both sides of the electrolyte layer. They are gas-permeable electrical conductors. The oxygen-ion-conducting electrolyte is provided as a thin membrane in order to be able to transport the oxygen ions with little energy. This only works at high temperatures. The outer side of the cathode facing away from the electrolyte is surrounded by air, the outer anode side of the fuel gas. Unused air and unused fuel gas as well as combustion products are suctioned off.

Due to the high application temperature, it is possible to use less noble (more cost-effective) materials, than the PEMFC and simultaneously achieve high power densities and high efficiencies. However, the high operating temperature is also the reason for almost all technical challenges. Mechanical stresses in operation have their origin mainly in temperature differences in the cell and by different thermal expansion coefficients of the materials. In addition there is the increased tendency to creep or oxidation processes or high-temperature corrosion.

At the moment not so many SOFC applications in DH systems exist. Especially in Europe there are just only few plants, mostly with demonstration character. That means the given CAPEX breakdown structure could vary, particular when the costs for the fuel cells decrease with higher market penetration.

Figure 44: CAPEX breakdown of solid oxide fuel cells

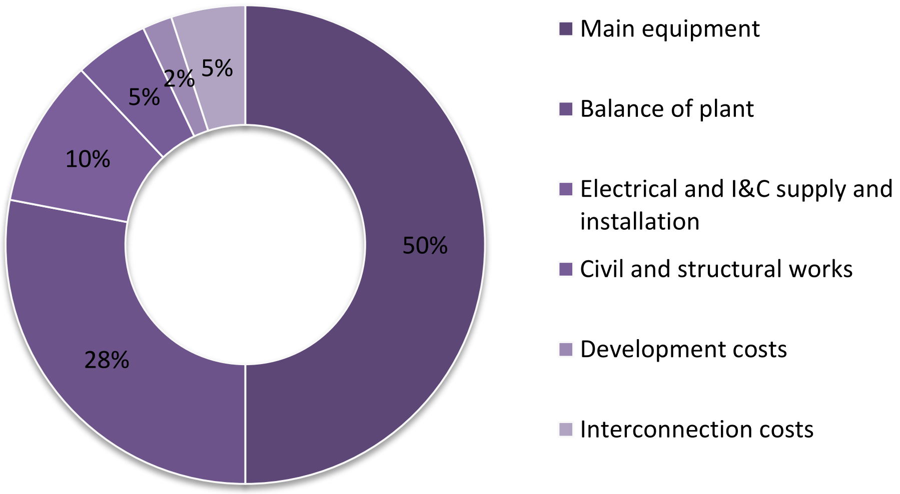

Table 39: Overview of solid oxide fuel cells

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Typical capacity size	MW_{el}	0.1 - 0.5											A	1
Electrical efficiency @peak electrical load	%	53	53	55	59	61							B	2
25 % load		45	50	52	53	55								3
Thermal efficiency @peak thermal load	%	32	32	32	34	34								2
Electricity consumption	%/MWth	4	4	3.5	3.5	3		3	5	2	4		C	4
Technical lifetime	years	5	6	10	12	15		3	8	10	20		D	5, 6
Steam supply		-	-	-	-	-		--	(-)	--	(-)			
Hot water		(-)	(-)	(-)	(-)	(-)		-	o	-	o			
Warm water		(o)	(o)	(o)	(o)	(o)		o	(+)	o	+			
Low temperature		+	+	+	+	+		(+)	++	(+)	++			
B. Environmental data (fuel: natural gas)														
CO2	$\mathrm{g/MJ}_{th}$	170	170	170	170	170							E	5
SO2	$\mathrm{g/GJ}_{th}$	0	0	0	0	0								5
NOX	$\mathrm{g/GJ}_{th}$	3.7	3.7	3.7	3.7	3.7								5
CH4	$\mathrm{g/GJ}_{th}$	25	25	25	25	25								5
N2O	$\mathrm{g/GJ}_{th}$	<	<	<	<	<								5
Particles	$\mathrm{g/GJ}_{th}$	negligible												5
C. Financial data														
Quality of CAPEX estimation		low												
Learning rate	%	15 - 18											F	7
Nominal investment	$\mathrm{M€/MW}_{el}$	15	8	4	3	2		6	15	1.5	5		G	2, 6, 7, 8
- of which equipment	$\mathrm{M€/MW}_{el}$	12	6	2.8	2	1.2		4.5	6.5	1.0	1.4			9, 10, 11, 12
- of which installation	$\mathrm{M€/MW}_{el}$	3	2	1.2	1	0.8		1.5	3.5	0.6	1.0			9, 10, 11, 12
Fixed O&M	$\mathrm{k€/MW}_{el}\mathrm{/a}$	N/A	N/A	N/A	N/A	N/A							H	9
Variable O&M excl. el. and fuel costs	$\mathrm{€/MWh}_{el}$	50	40	30	20	10							I	2, 3, 9, 13

X. Technology specific data													
Heat to power ratio	1	0.6	0.6	0.58	0.57	0.56							2
Fuel to cell		Hydrogen, Natural gas, biogas, coal gas										J	5
Working temperature	°C	750	750	650	650	650		500	1 100	400	800	K	1, 3, 14
Construction time	months	10	8	6	5	4		5	10	3	5		13
Start time	min	45	30	25	20	15		20	50	15	60	L	15
Availability	%	98	99	99	99	99							15
Degradation with cycling	%/1 000 h	<0.5	<0.3	<0.2	<0.2	<0.1							15

References:

1 Fuel Cells for Stationary Applications; IEA ETSAP, January 2013
2 Energy Technology Reference Indicator projections for 2010-2050; JRC, 2014
3 Technology Data for Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion; Energinet.dk, May 2012
4 Stationäre Brennstoffzellen (Projektergebnisse der ARGE-Brennstoffzelle, Advanced Fuel Cell Workshop); H. Wilk, September 2006
5 FUEL CELLS - Impact and consequences of Fuel Cells technology on sustainable development; D. Oertel and T. Fleischer, March 2003
6 Technology Roadmap - Hydrogen and Fuel Cells; OECD/IEA, 2015
7 The cost of domestic fuel cell micro-CHP systems; Staffell and Green, 2012
8 Best available technologies for the heat and cooling market in the European Union; JRC, 2012
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10 Technology Data for Energy Plants - Individual Heating Plants and Energy Transport; Energinet.dk, May 2012
11 Fuel Cells (Presentation); E. Allen, 2012
12 Fuel Cells - Selected Entries from the Encyclopedia of Sustainability Science and Technology; K.-D. Kreuer, 2013 © Springer Science+Business Media New York
13 Levelized Cost of Energy Analysis; Lazard, 2014
14 The role of hydrogen and fuel cells in providing affordable, secure low-carbon heat; H2FC SUPERGEN, 2014
15 1–10 kW Stationary Combined Heat and Power Systems Status and Technical Potential; NREL, May 2010

Notes:

A Fuel cells are modular in nature. Therefore, systems can be connected together to create large installations (to the range of megawatt capacities).
B Based on lower heating value (LHV).
C Measured operational data from the SOFC System in Attnang-Puchheim, Austria.
D Lifetime is calculated with 8 000 operation hours per year. End of operating time is defined until > 20 % net power degradation is reached.
E Emissions based on fuel consumption. None of the listed emissions occurs if fuel cell is operated on pure hydrogen by electrolysis.
F Ref. 13 notes that the prices offered by several manufacturers are falling by 15 - 18 % for each doubling of cumulative systems shipped.
G Fuel treatment (e.g. methane reformer / electrolyser) is included but no building. At the moment fuel cells have high investment costs, but relevant stakeholder (e.g. Department of Energy (DoE), USA; Japanese ministry METI/NEDO) projects long term capital cost for larger systems below MEUR 3/MW_{el} till 2050. Small-scale fuel cells are projected between MEUR 3 - 5/MW_{el}.
H According to Ref. 9, most FC operators do not treat O&M on a fixed basis, and consequently, all O&M expenses are shown on a variable basis.
I Mainly caused by service and maintenance (e.g. change of filters, fuel cell stacks, etc.). Recommended service is comprised of routine short interval

inspections/adjustments and periodic replacement of filters (projected at intervals of 2 000 to 4 000 hours).

J Coal gas: internal reforming in the fuel cells is possible.

K Depending on the design, SOFCs operates at temperatures between 500 and 1 000 °C. High operating temperature allows cheaper catalysts (like nickel and lanthanum to be used in place of platinum), but means that all components must be able to withstand extreme thermal stresses. Ignoble catalysts are more tolerant to impurities, so fuel processing is simpler, and in some cases the fuel cell can use sulphur-free methane (CH4) directly as a fuel. Fundamental research has been aimed at improving durability and material fatigue. Moreover, there is a trend moving operating intermediate temperature towards 500 – 750 °C. This allows a wider range of materials to be used, lowering costs and improving dynamic performance (Ref. 14).

L Start-up time from 20 °C ambient temperature. Transient response (10 - 90 % rated power) will be between 1 - 3 minutes.

7 Other / Auxiliary Systems

7.1 District heating substations

A DH substation is a technical device which transfers the heat of a district heating network to the customer's heat distribution system (also known as secondary side), thereby setting the supply temperature desired by the customer in his distribution system. Substations can be operated on the primary side with steam or hot water.

Depending on the application, there are different requirements for a substation. For example, each building has a specific heating requirement, each district heating company has specific technical requirements to the connections and each customer individual heating habits. These factors influence the selection of the stations for the heat distribution in buildings and places or in small and large district heating networks.

The size of a station is determined by the heat demand of the customer to be supplied. Temperature and pressure of the primary power supply determine whether a station should be operated directly or indirectly.

In addition, many district heating networks define special technical connection conditions, which require special components / solutions. Finally, the number and type of heating circuits as well as the type of drinking water heating influence the selection of the required appliances.

Stations in the power range of 10 up to 500 kW are standard products. These can be designed for direct or indirect operation, with one or more heating circuits. Furthermore, hot water preparation solutions are offered in various variants.

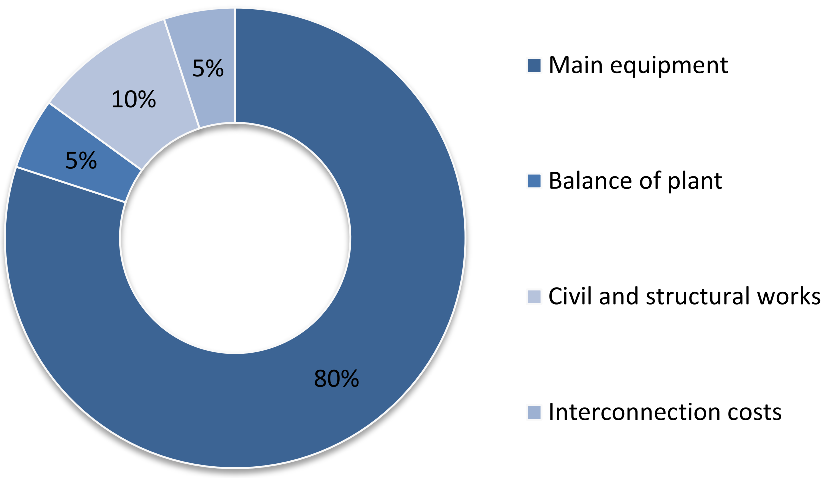
Substations mainly consist of heat exchangers, side strainers (primary and secondary), control valve, heat meter and other small devices.

Main tasks of substations are:

- Measuring the heat consumption of the customer by the heat meter
- Controlling the primary differential pressure
- Limitation of the flow rate of the district heating water to its contract performance
- Hydraulic separation of the district heating system to the house installation by heat exchanger
- The limitation of the secondary return temperature by means of a temperature sensor arranged in the secondary circuit (customer circuit) which automatically resets the heating power or sets the flow temperature of the customer higher than the flow temperature dependent on the outside temperature
- Limitation of the supply temperature by a safety temperature regulator
- Hot water preparation

The following CAPEX breakdown structure is based on small-scale substations for single-/ multifamily houses. The substation itself has the highest, as it is assumed that enough space is available at the installation site and therefore just small installation effort is necessary

Figure 45: CAPEX breakdown of small-scale substations for single-/ multifamily houses



The CAPEX breakdown structure below is based on large-scale substations for apartment block / industrial purposes. The substation itself has only a small influence on the total investment. On the other hand higher installation effort is needed (e.g. adaption / creating of buildings, interconnection, etc.).

Figure 46: CAPEX breakdown of large-scale substations for apartment block / industrial purposes

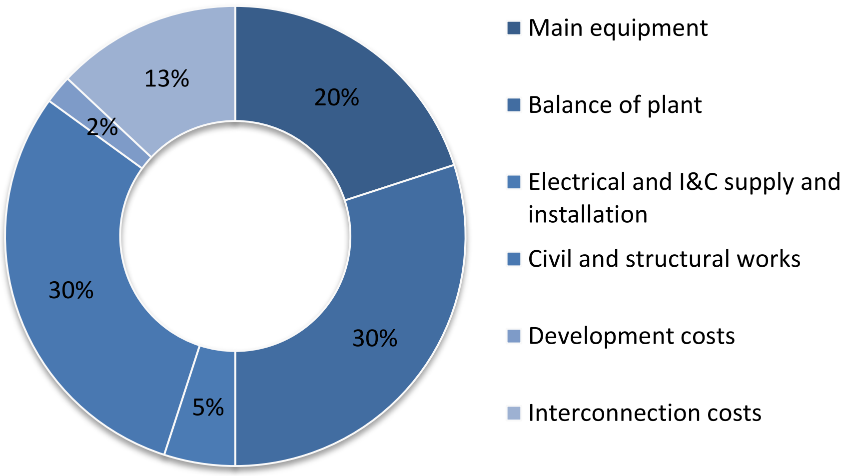


Table 40: Overview of small-scale substations for single-/ multifamily houses

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Heat generation capacity	MW$_{th}$	0.01 - 0.5											A	1, 2
Total efficiency, nominal load	%	98	98	98	98	98		97	99	97	99		B	1, 2, 3
Total efficiency, annual average	%	95	95	95	95	95		93	99	93	99		C	1, 2, 3
Electricity consumption	%/MWh$_{th}$	negligible											D	1, 2
Technical lifetime	years	20	20	20	20	20		20	>20	20	>20			1, 2, 3, 4
Steam supply		N/A	N/A	N/A	N/A	N/A							E	
Hot water		(-)	(-)	(-)	(-)	(-)		-	o	-	o		F	
Warm water		(o)	(o)	(o)	(o)	(o)		o	o	o	o			
Low temperature		(+)	(+)	(+)	(+)	(+)		o	+	o	+			
B. Environmental data														
CO2	g/MJ$_{th}$	0	0	0	0	0								
SO2	g/GJ$_{th}$	0	0	0	0	0								
NOX	g/GJ$_{th}$	0	0	0	0	0								
CH4	g/GJ$_{th}$	0	0	0	0	0								
N2O	g/GJ$_{th}$	0	0	0	0	0								
Particles	g/GJ$_{th}$	0	0	0	0	0								
C. Financial data														
Quality of CAPEX estimation		high												
Learning rate	%												G	
Nominal investment	M€/MW$_{th}$	0.076	0.074	0.073	0.072	0.070		0.035	0.210	0.030	0.200		H	1, 2, 5, 6
- of which equipment	M€/MW$_{th}$	0.060	0.059	0.059	0.058	0.056		0.055	0.065	0.050	0.060			1, 2
- of which installation	M€/MW$_{th}$	0.016	0.015	0.014	0.014	0.014		0.009	0.019	0.010	0.020		I	1, 2
Fixed O&M	k€/MW$_{th}$/a	0.125	0.125	0.125	0.125	0.125		0.10	0.15	0.10	0.15		J	1, 2
Variable O&M excl. electricity costs	€/MWh$_{th}$	0	0	0	0	0							K	1, 2, 3
X. Technology specific data														
Cost function (estimation)	M€/MW$_{th}$	Invest(x)=0.026$x^{-0.46}$											L	7
Construction time	days	1	1	1	1	1		0.5	>2	0.5	>2		M	1, 2

References:

1 Information of Danfoss, Communications between March - May 2017 (www.danfoss.com)
2 Manufacturers and planners information, 2017
3 Technology Data for Energy Plants - Individual Heating Plants and Energy Transport; Energinet.dk, May 2012
4 VDI 2067 - Economic efficiency of building installations, 2012
5 Ermittlung von spezifischen Kosten energiesparender Bauteil-, Beleuchtungs-, Heizungs- und Klimatechnikausführungen bei Nichtwohngebäuden für die Wirtschaftlichkeitsuntersuchungen zur EnEV 2012; BMVBS (Bundesministerium für Verkehr, Bau und Stadtentwicklung), August 2012
6 Praxisbuch Energiewirtschaft - Energieumwandlung, -transport und -beschaffung im liberalisierten Markt; K. Panos, 2013 © Springer-Verlag Berlin Heidelberg
7 Klimaneutraler Gebäudebestand 2050; Umweltbundesamtes, 2016 (http://www.umweltbundesamt.de/publikationen/klimaneutraler-gebaeudebestand-2050)

Notes:

A Given sizes are typical for one-family houses up to multy-family houses (small apartment complex).
B The losses of DH substations depend on the quality of insulation and could be counted to 1 - 2 %, resulting in 98 - 99 % efficiency.
C Due to part load operation the annual efficiency could be lower as the losses increases in relation.
D The electrical consumption of DH substations through the control is negligibly small. Typically the actuator has a consumption of appr. 5 - 10 W but is not often in operation (should be lower than 10 minutes a day - if it is more frequently in operation, this indicates a poor adjustment). Pump is not included because it depends on the situation of the secondary side installation.
E Steam application is not any more state of the art for DH customers (especially for residential buildings).
F DH substation could be used for a broad temperature range. The technical configuration depends essentially on the temperature levels and differences.
G No high learning rates are seen for this technology as standardized and well developed components are used.
H Given CAPEX estimation (2015-2050) is based on a 100 kW_{th} DH substation. For other thermal power ranges the given cost function could be used. Note: The cost estimation assumes that enough space is available at the installation site. That means the highest costs are caused by the substation itself.
I Installation effort to connect DH substation on primary side: 4 - 8 h x 2 persons in the range of 10 - 500 kW_{th} depending on-site conditions.
J Note, that the fixed O&M costs stay constant independent of the substation size. Manufacturers recommend maintenance (leak test, checking strainer, function check, ...) every two years. Maintenance effort will be estimated to 2 h every second year (manufacturers estimate the effort with EUR 250 incl. travel lump sum which equals EUR 125 per year).
K Except electricity, no variable O&M costs occur.
L Cost function is based on the given reference and adjusted to prices from manufacturers and replicates full costs. x…Heat generation capacity [10 kW_{th} … 500 kW_{th}]
M Includes only interconnection on site. Construction time respectively necessary man hours could rapidly increase with difficult accessable locations (this must be considered specifically).

Table 41: Overview of large-scale substations for apartment block / industrial purposes

	Unit	**2015**	**2020**	**2030**	**2040**	**2050**		**Uncertainty (2020)**		**Uncertainty (2050)**			**Note**	**Ref**
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Heat generation capacity	MW$_{th}$	1 - 20											A	1, 2
Total efficiency, nominal load	%	99	99	99	99	99		98	100	98	100		B	1, 2, 3
Total efficiency, annual average	%	98	98	98	98	98		95	100	95	100		C	1, 2, 3
Electricity consumption	%/MWh$_{th}$	negligible											D	1, 2
Technical lifetime	years	20	20	20	20	20		20	>20	20	>20			1, 2, 3, 4
Steam supply		-	-	-	-	-		--	(-)	--	(-)		E	
Hot water (up to 140 °C)		(-)	(-)	(-)	(-)	(-)		-	o	-	o		F	
Warm water (up to 105 °C)		(o)	(o)	(o)	(o)	(o)		o	o	o	o			
Low temperature (up to 70 °C)		(+)	(+)	(+)	(+)	(+)		o	+	o	+			
B. Environmental data														
CO2	g/MJ$_{th}$	0	0	0	0	0								
SO2	g/GJ$_{th}$	0	0	0	0	0								
NOX	g/GJ$_{th}$	0	0	0	0	0								
CH4	g/GJ$_{th}$	0	0	0	0	0								
N2O	g/GJ$_{th}$	0	0	0	0	0								
Particles	g/GJ$_{th}$	0	0	0	0	0								
C. Financial data														
Quality of CAPEX estimation		medium												
Learning rate	%												G	
Nominal investment	M€/MW$_{th}$	0.100	0.099	0.098	0.097	0.095		0.085	0.150	0.080	0.130		H	1, 2, 5, 6
- of which equipment	M€/MW$_{th}$	0.030	0.029	0.029	0.029	0.028		0.02	0.04	0.019	0.038			1, 2
- of which installation	M€/MW$_{th}$	0.070	0.070	0.069	0.068	0.067		0.06	0.08	0.057	0.076			1, 2
Fixed O&M	k€/MW$_{th}$/a	0.5	0.5	0.5	0.5	0.5		0.3	0.7	0.3	0.7		I	1, 2
Variable O&M excl. electricity costs	€/MWh$_{th}$	0	0	0	0	0							J	1, 2, 3
X. Technology specific data														
Construction time	months	0.5	0.5	0.5	0.5	0.5		0.3	1	0.3	1		K	

References:

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2 Manufacturer and planner information, 2017

3 Technology Data for Energy Plants - Individual Heating Plants and Energy Transport; Energinet.dk, May 2012

4 VDI 2067 - Economic efficiency of building installations, 2012

5 Ermittlung von spezifischen Kosten energiesparender Bauteil-, Beleuchtungs-, Heizungs- und Klimatechnikausführungen bei Nichtwohngebäuden für die Wirtschaftlichkeitsuntersuchungen zur EnEV 2012; BMVBS (Bundesministerium für Verkehr, Bau und Stadtentwicklung), August 2012

6 Project information, 2013

Notes:

A Given sizes are used for big apartment complex and industrial purposes.

B The losses of DH substations depend on the quality of insulation and could be counted to 1 %, resulting in 99 % efficiency.

C Due to part load operation the annual efficiency could be lowered as the losses increases in relation.

D The electrical consumption of DH substations through the control is negligibly small. Typically the actuator has a consumption of appr. 15 - 20 W but is not often in operation (should be lower than 10 minutes a day - if it is more frequently in operation, this indicates a poor adjustment). Pump is not included because it depends on the situation of the secondary side installation.

E Steam applications could significantly increase the investment costs due to special requirements.

F DH substation could be used for a broad temperature range. The technical configuration depends essentially on the temperature levels and differences.

G Equal to small DH substations, no high learning rates are seen for this technology as standardized and well developed components are used. The future development of raw material prices (especially steel price) will have the strongest influence.

H Given cost estimation is based on a 10 MW_{th} DH substation. Note: Substations of these sizes are mainly individual customized products. That means, that in large-scale applications the substation itself is only a small part of the investment cost. Most costs are dedicated through the given conditions on-site, especially when an own building or adaptions are needed.

I Maintenance check (leak test, checking strainer, fuction check, etc.) will be done every year and the effort will be a little bit higher in comparison to small DH substations.

J Except electricity, no variable O&M costs occur.

K Construction time for large-scale substations is very on-site specific and could have a high spread.

7.2 District heating piping networks

District heating (DH) systems provide heat for space heating and hot water to residential, commercial and service buildings, and to industrial users. Heat is generated centrally or derived from an existing heat source and distributed to consumers by pipelines. As the first systems were mainly operated by steam (also known as 1st Generation DH systems), these days hot water used.

Until about 40 years ago, district heating pipes were installed almost exclusively in concrete ducts. This type of laying is found in new discoveries because of the high costs only in special cases. Nowadays, ground-buried plastic sheath pipes are used as district heating pipes. Typically, the pipes consist of the steel medium pipe, the polyurethane thermal insulation and the plastic sheath. In most cases, sensors are also installed for a leak warning system. At high load, e.g. crossing roads, steel mantle pipes are also used. For local heating networks with low flow temperatures, flexible plastic medium pipes are increasingly used.

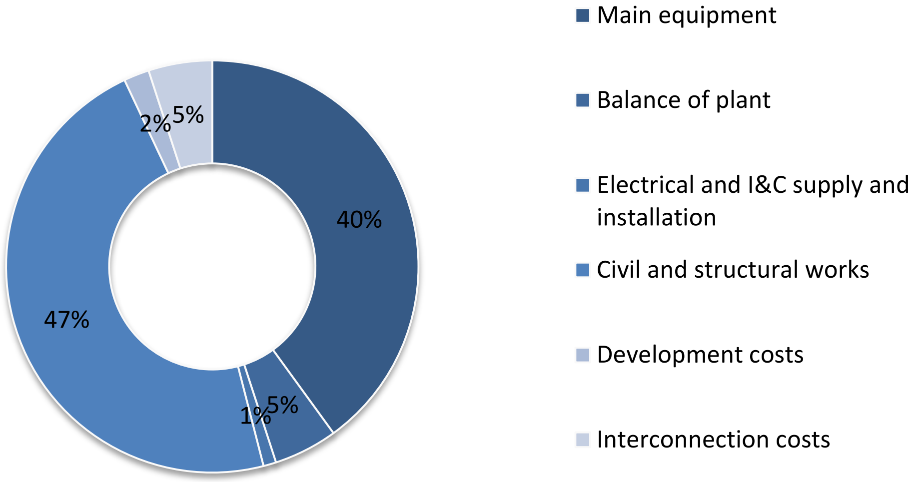
Most heating water networks are designed for a maximum supply temperature of 130 °C. This is due to the highest temperature that the polyurethane heat protection of today's most widely used plastic sheathed pipes can withstand in continuous operation. This temperature, however, is only required for high heat demand peaks in winter. As a rule, the feed temperature is moved slidingly between 70 °C and 130 °C as a function of the ambient air temperature. The lowest supply temperature of 70 °C is necessary to ensure domestic hot water preparation at 60 °C. The return temperature is normally designed to be below 70 °C. Low water temperatures in both the supply and return line are energetically advantageous because the district heat extraction can be carried out in CHP plants at lower pressures and thus a higher current yield is achieved. This also makes heat production costs more favourable. Furthermore, a lower water temperature also reduces the heat losses in the network. In modern grids, a constant return temperature of 50 °C is also aimed in addition to the sliding temperature control in the supply line.

Indicators such as connection density (connections per km²) and linear heat density (MWh/(m.a)) are indicators for the first assessment of the economic viability of the district heating supply of potential supply areas or consumers.

Since prices for materials and work are constantly changing and the planning process between a pre-study and implementation of district heating systems can take several years, any adjustments to the costs must be taken into account during implementation. Seasonal differences are also possible, in particular, for civil engineering work. Compared to favourable conditions, additional costs can arise due to specific situations, in particular due to the high complexity of the line management (for example cobblestone pavements, river crossings, motorways, railway tracks).

Guideline values for laying costs of district heating pipes as a function of diameter are shown in the following CAPEX breakdown structure. Civil engineering works costs account between 40 to 50 %. However, they are strongly dependent on the soil structure and the degree of difficulty of the laying. In the inner city area, the laying costs can therefore be considerably above the specified bandwidth. The other major costs are caused by the pipes themselves.

Figure 47: CAPEX breakdown of DH piping networks



Estimating DH piping costs on macro-scale

With the following approach the piping costs for a DH supply area could be estimated. This method allows to go from Euro per rout meter (rm) to the macro-scale. Therefore, the building density “e[11]” [m^2_{GFA}[12]/$m^2_{Landarea}$] and the specific heat demand [$kWh/m^2_{GFA}.a$] has to be known.

Example

The DH piping cost for a supplying area has to be estimated. The building density “e” is assumed to be 0.4 (equals outer city area) and the specific heat demand with 150 $kWh/(m^2_{GFA}.a)$.

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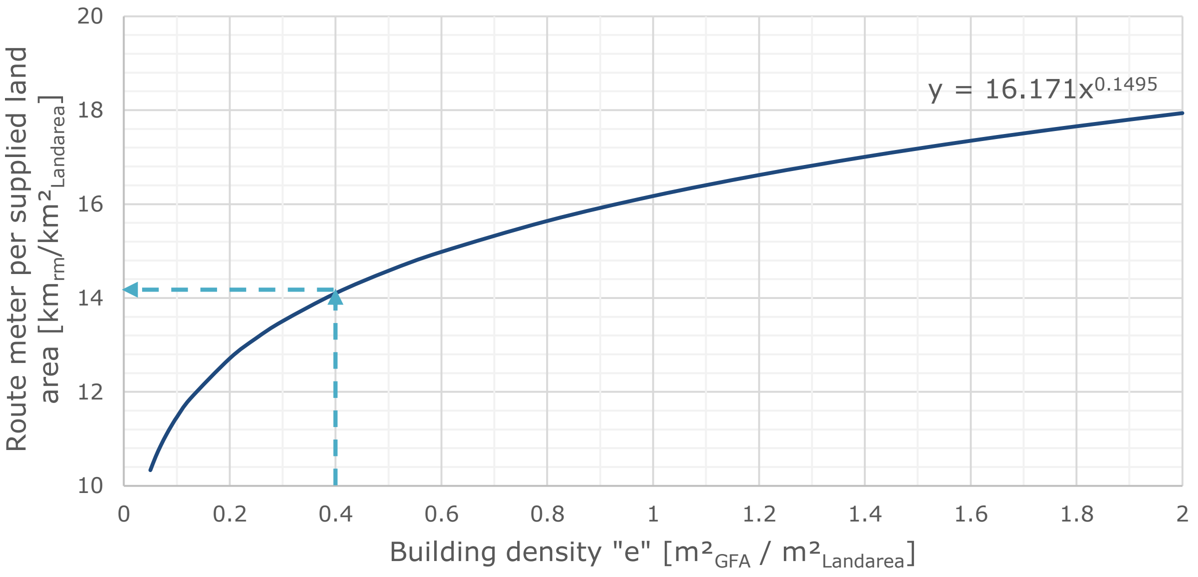
[11] Typical values are: Inner city areas: $e \geq 0.5$ | Outer city areas: $0.3 \leq e < 0.5$ | Park areas: $0 \leq e < 0.3$

[12] GFA … Gross floor area

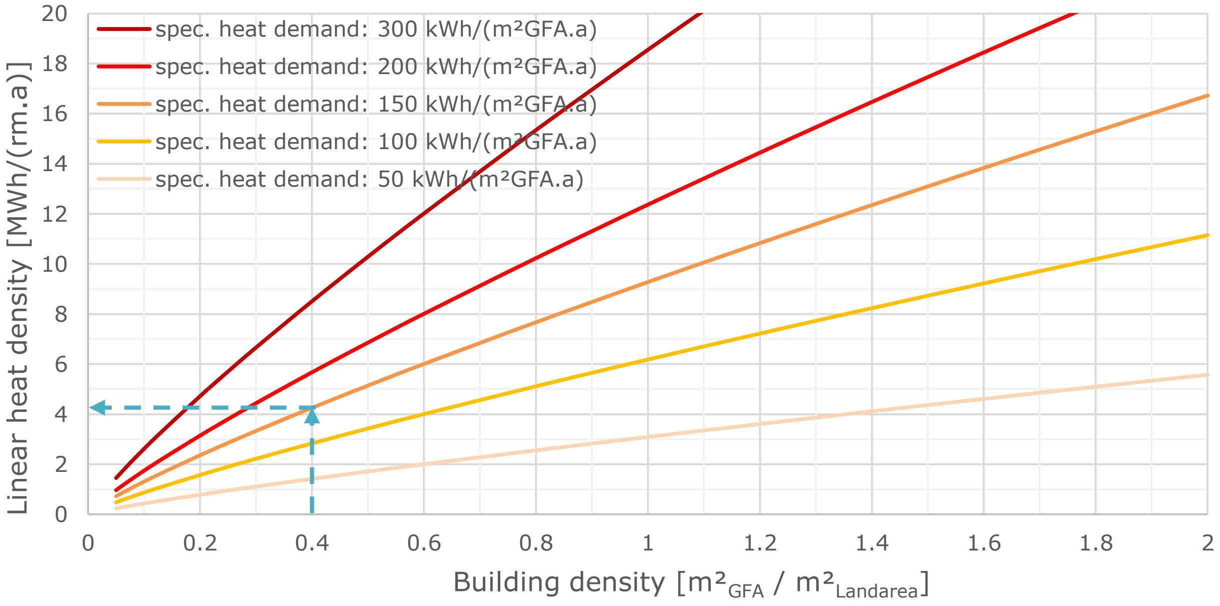
Figure 48: Route meter per land area as a function of the building density



Source: Heat distribution and the future competitiveness of district heating, U. Persson and S. Werner, 2011 (modified)

Using the graphic above, a value of 14.1 $km_{rm}/km^2_{Landarea}$ could be figured out. With the next figure the linear heat density could be determined, which is 4.3 MWh/(rm.a) in this case.

Figure 49: Linear heat densitiy of DH networks as a function of the building density "e" and the specific heat demand per ground floor area (GFA)



Source: Heat distribution and the future competitiveness of district heating, U. Persson and S. Werner, 2011 (modified)

Knowing the linear heat density, the average pipe dimension could be calculated with the given function "Average pipe dimension". Furthermore, the costs per route meter could be estimated through the given cost function (formulas see in the technology). Multiplying the specific costs (EUR/rm) by the route meters per supplied land (first figure) the DH piping network costs could be calculated on macro-scale. The benefit of the given cost function is the higher accuracy on macro-scale due to the consideration of different conditions.

For the given example, the average pipe dimension will be DN 133 and the costs are calculated to EUR 563 per route meter. The total DH piping costs on macro-scale could be estimated to approx. 8 million Euro.

Adding the costs for DH substations (cost function is given in the appropriate technology table), the total investment costs for a DH piping system could be calculated.

Table 42: Overview of DH piping networks

	Unit	**2015**	**2020**	**2030**	**2040**	**2050**		**Uncertainty (2020)**		**Uncertainty (2050)**			**Note**	**Ref**
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Linear heat density	MWh/(m.a)	1 - 5						1	>5	1	>5		A	1, 2, 3
Net loss	%	10	10	10	10	10		5	20	5	20		B	3, 5
Electricity consumption	%/MWh$_{th}$	1	1	1	1	1		0.5	1.5	0.4	1.5		C	3, 4
Technical lifetime	years	30	30	35	35	35		25	40	30	45		D	4, 5, 6
Steam supply		--	--	--	--	--		--	-	--	-		E	
Hot water		-	-	-	-	-		--	(-)	--	(-)		F	
Warm water		(o)	(o)	(o)	(o)	(o)		o	(+)	o	(+)			
Low temperature		+	+	+	+	+		o	++	o	++			
B. Environmental data														
CO2	g/MJ$_{th}$	0	0	0	0	0								7
SO2	g/GJ$_{th}$	0	0	0	0	0								7
NOX	g/GJ$_{th}$	0	0	0	0	0								7
CH4	g/GJ$_{th}$	0	0	0	0	0								7
N2O	g/GJ$_{th}$	0	0	0	0	0								7
Particles	g/GJ$_{th}$	0	0	0	0	0								7
C. Financial data														
Quality of CAPEX estimation		medium												
Learning rate	%												G	8
Nominal investment	€/rm	500	498	496	494	490		300	800	270	750		H	5, 9, 10, 11
- of which equipment	€/rm	200	199	198	197	196		150	249	147	245			10, 11
- of which installation	€/rm	300	299	298	297	294		249	348	245	343			10, 11
Fixed O&M	%/CAPEX/a	1	1	1	1	1							I	4, 6, 7, 12
Variable O&M excl. electricity costs	€/MWh	N/A	N/A	N/A	N/A	N/A								
X. Technology specific data														
Cost function (estimation)	€/rm	$C_{DH-Pipenetwork}(DN) = (270 + 2.2*DN) * (1+f_{GroundCondition}) * (1+f_{PipingSystem})$											J	11, 13, 14
Average pipe dimension	DN	DN = 48.6 * ln (linear heat density [MWh/(rm.a)]) + 63											K	4, 13, 15, 16
Typically pipe dimension	DN	20 - 300											L	10
Suggested flow velocity	m/s	$v._{flow} = 0.14 * DN^{(0.5)}$											M	14
Maximum pressure drop	Pa/m	<200 - 300											N	17, 18
Temperature differences	K	30 - 60											O	3, 9

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Notes:

A The linear heat density describes the annual sold heat quantity per trench length. Experience has shown that DH networks should have a linear heat density above 0.9 MWh/(m.a) in order to be economic feasible. Typical linear heat density values are: rural = 0.9 - 1.7; sub urban = 1 - 2; urban = 1 - >5 MWh/(m.a).
B The heat losses depend on factors such as linear heat density, distribution temperatures, piping insulation material and average pipe diameter. Heat losses could range from 5 - 8 % in densely populated cities up to 25 - 30 % in low heat density areas.
C Including pumping and MCR effort. The pumping energy required by the distribution system depends on the size and complexity of the network. Typically, pumping effort is about 5 - 10 kWh_{el} per MWh_{th} of delivered heat. E.g. For a typical annual temperature difference between supply and return pipes of 35 K and a total pressure drop of 6 bar, the relative pumping electricity demand is approx. 0.5 % of the delivered heat.
D DH networks have long lifetimes over 30 years. For economic assessment calculations a period over 30 years is common.
E Some distribution networks for industrial plants are supplied with steam at a high temperature level for process heat. Nevertheless, DH systems with steam for only heating applications are unusual these days and existing ones are converted to water systems. Disadvantages for steam DH systems are higher investment costs and less good controllability.
F The heat distribution is largely made with plastic casing pipes which limit the continuous operating temperatures to 120 - 140 °C. Note: Higher operating temperatures need higher requirements (pressure resistance, steal jacket pipe, etc.) which influence the investment costs.
G Learning rate is seen as quite low as it is a mature technology. The greatest cost reduction potential is seen in new and faster laying procedures.
H Given CAPEX estimation (2015 - 2050) is based on a DN 100 piping network. The lower and upper cost estimates are based on realised projects with different pipe dimensions (range see "typically pipe dimension" below) and provided by a DH network operator. According to this information, the prices are between EUR 330 -

600/rm for unsurfaced areas and between EUR 400 - 750/rm for city areas. Note: As prices for materials and labour are constantly changing and the planning process between pre-studies and implementation of district heating systems can take several years, any adjustments to the costs must be taken into account during implementation. Seasonal differences are also possible, in particular, for civil engineering work (especially the excavation consumes a high effort and the prices are influenced a lot through the respective capacity utilization of the construction companies). Compared to favourable conditions, additional costs can arise due to specific situations, in particular due to high complexity of piping routing (for example cobblestone pavements, river crossings, motorways, railway tracks).

I The annual operation and maintenance costs are often considered to be about 1 % of the total capital investment cost or about 10 - 15 % of the (annual) DH distribution costs.

J The given formula should represent a simplified approach to predict the costs of DH piping networks in EUR per route meters considering pipe diameter, pipe material and construction area. The formula is built on published cost data from the listed references. The ground formula is based on a plastic casing pipe with ground condition "outer city area". The given factors $f_{GroundCondition}$ and $f_{PipingSystem}$ describes correction factors which should replicate different construction areas and pipe materials. Considering different applications the factors have to be adapted as follow $f_{GroundCondition}$: Construction areas = -50 %; Green areas = -25 %; Outer city areas = 0 %; Inner city areas = +25 % | $f_{PipingSystem}$: Concrete pipe = +75 %; Steel jacket pipe = +40 %; Plastic casing pipe = 0%; Free terrain pipe = -20 %. Note: As the formula intends to generalize costs for different circumstances, deviations must be accepted.

K Formula is based on an investigation of 134 Swedish DH networks or section of networks and shows that, on average, higher linear heat densities require greater pipes. Combining the above the formula values indicates systems of high flow designed for low temperature differences between supply and return line. Note: Accurate diameter dimensioning is very important because oversizing will lead to much higher investment costs.

L Most common pipe diameters in DH networks range from DN 20 - 300. Pipe diameters above DN 300 are mostly needed for transport pipes and therefore special requirements may apply and also the cost estimation could have a higher spread.

M The formula is based on indications for flow velocities in district heating pipes (according to the given reference) and depends of the nominal diameter (DN). Flow velocities for steam applications in medium and low pressure pipes are commonly between 30 - 50 m/s.

N Different plant planning guides and pipe manufacturers recommend that the pressure drop should not exceed 300 Pa/m. Typical values for planning DH piping networks are 90 - 150 Pa/m.

O Typical supply temperature levels are up to 90 °C for small (rural) and above 130 °C for large (e.g. big cities) DH systems.

7.3 Thermal heat storages

7.3.1 Pit thermal energy storages

The technology of large-volume seasonal heat storage has been explored in Europe since the mid-1970s. The first test facility was implemented in Sweden in late 1970 in the course of a national research program. Denmark, in particular, increasingly relies on large-volume seasonal storage in combination with appropriately dimensioned solar collectors to supply the solar heat produced during the summer months, and in winter for heating purposes. At the same time, there are also plans in other countries to implement seasonal storage that go beyond the pilot stage. For example, the "Big Solar Graz" project in Austria provides for international attention.

The use of long-term heat storage makes it possible to replace fossil fuels with renewable energy sources. In addition, this technology is suitable to use industrial waste heat, to reduce peak loads and to create a degree of freedom between electricity and heat generation. In this work, the two types pit thermal energy storage (PTES) and Aquifer thermal energy storage (ATES) are considered.

Seasonal storage is used mainly in solar-assisted local heating systems to increase the solar coverage of heat demand. Some plants in Denmark reach solar coverage levels of up to 50 percent. Most of the long-term heat storages are run as a PTES. Due to the pressureless design, the maximum usable temperature level is below 100 °C, most of which are charged up to 85 °C in practice. The lower usable temperature range is determined by the return temperature of the coupled heating network. For most plants in Denmark this is about 40 °C (which is comparatively low). In order to increase the thermal heat capacity, heat pumps are increasingly used.

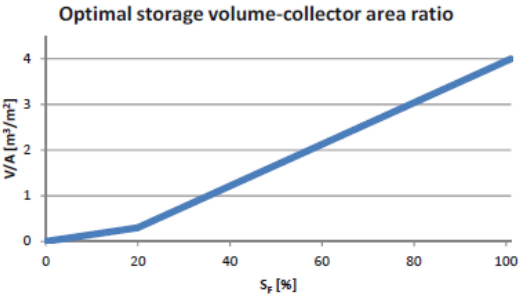
The choice for the appropriate storage concept must be explicitly considered for each system. Local geological conditions, system integration, required storage capacity, performance and temperature levels, number of cycles per year, legal framework must be considered. For geothermal heaters and aquifer heat accumulators, higher administrative requirements usually apply, especially with regard to water regulations. Ultimately, the economic feasibility, taking into account all the full costs, plays a decisive factor. The costs are also heavily influenced by local land prices. In the plant concepts of ATES, buffer storages are also usually provided to be independent of the limiting effect due to maximum loading capacities.

For implementing long-term storages, it is important to consider that the storages (depending on the storage type) require some time to be settled and fully operational. For ATES, this can take 2 till up to 5 years. During this phase, the adjacent soil is heated, which means that heat losses are also higher.

The economics of systems with long-term heat storage is determined not only by the costs but also depends on the performance of the storage itself and on the system configuration. Therefore, no general statement can be made as to which type of memory is most economical. Rather, every system has to be examined for itself with regard to the full costs (investment, maintenance and operation). Scale effects have the effect that the specific investment costs decrease with increasing storage size, and a minimum size of 2 000 m^3 of water equivalent (WE) is recommended.

The figure below can be used as a first estimation of the storage size. But especially for large solar fractions - and if combined with other technologies - the storage size should be carefully optimized with detailed calculations/simulations.

Figure 50: First rough estimation of optimal ratio between storage volume and collector area as function of solar fraction

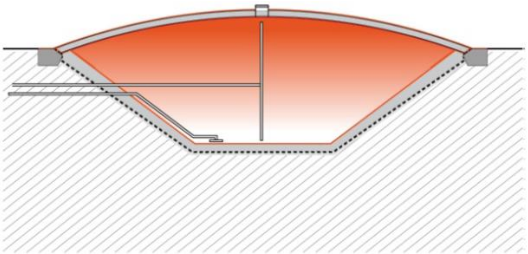


Source: Solar district heating guidelines

PTES are normally built without static construction. They are mainly built by excavation on site and are equipped with a heat-insulating cover and a waterproof film. As a heat storage medium pure water as well as gravel / sand / rock in combination with water is possible. The largest storages with up to 100 000 m³ are located in Denmark.

Relative to the specific investment costs per m³ (water equivalent), PTES storage is somewhat more expensive than ATES. However, the former have advantages in terms of thermodynamic properties and are less dependent on the geological conditions. The sealing and film lining is a major cost factor. Requirements of the materials to be used are the temperature, humidity and pressure resistance as well as a long service life.

Figure 51: Construction concept of pit thermal energy storages (PTES)



Source: Solites

The predominant cost components of PTES are the foil liner and the thermal insulation (share approx. 50/50 of the main equipment costs). The category "Civil and structural works" in the CAPEX breakdown structure includes the excavation works.

Figure 52: CAPEX breakdown of pit thermal energy storages (PTES)

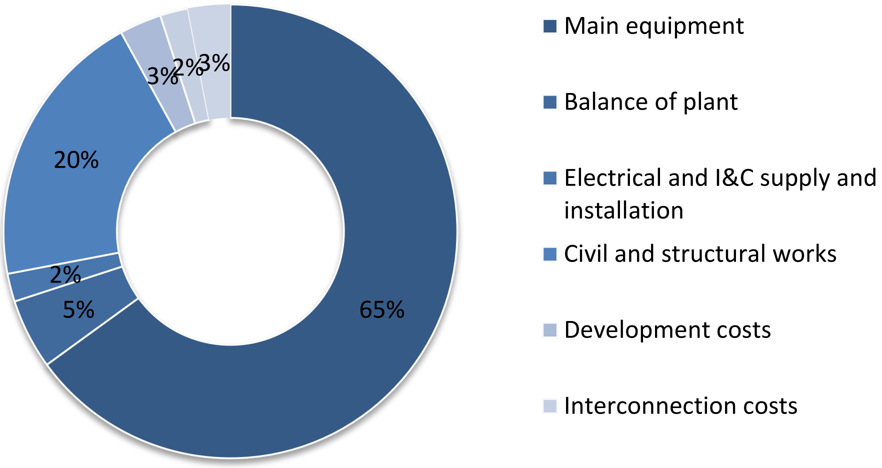


Table 43: Overview of pit thermal energy storages (PTES)

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Heat storage volume (water equivalent)	m^3_{WE}	20 000 - 200 000											A	1, 2, 3
Storage capacity	kWh/m^3_{WE}	60 - 80						50	85	50	90		B	3, 4, 5
Efficiency, annual average	%	50 - 90						40	90	45	95		C	3, 5, 6
Electricity consumption	%/MWh_{th}	1	1	1	1	1		0.8	1.2	0.8	1.2		D	3, 5
Technical lifetime	years	20	20	25	25	25		17	>25	20	>25		E	3, 5
Steam supply		N/A	N/A	N/A	N/A	N/A							F	
Hot water		N/A	N/A	N/A	N/A	N/A								
Warm water (up to 90 °C)		o	o	o	o	o		o	(+)	o	(+)		G	
Low temperature		+	+	+	+	+		(+)	++	(+)	++			
B. Environmental data														
CO2	g/MJ_{th}	0	0	0	0	0							H	
SO2	g/GJ_{th}	0	0	0	0	0								
NOX	g/GJ_{th}	0	0	0	0	0								
CH4	g/GJ_{th}	0	0	0	0	0								
N2O	g/GJ_{th}	0	0	0	0	0								
Particles	g/GJ_{th}	0	0	0	0	0								
C. Financial data														
Quality of CAPEX estimation		medium												
Learning rate	%												I	
Nominal investment	M€/MW_{th}	0.43	0.4	0.38	0.36	0.34		0.30	0.70	0.25	0.60		J	7, 8, 9, 10
- of which equipment	M€/MW_{th}	0.13	0.12	0.11	0.11	0.10		0.08	0.2	0.07	0.17			11, 12
- of which installation	M€/MW_{th}	0.30	0.28	0.27	0.26	0.24		0.2	0.32	0.17	0.27			11, 12
Fixed O&M	k€/MW_{th}/a	4.3	4	3.6	3.4	3.2		3.2	4.8	2.4	3.7		K	4, 5, 12, 13
Variable O&M excl. electricity costs	€/MWh_{th}	N/A	N/A	N/A	N/A	N/A								
X. Technology specific data														
Cost function (estimation)	€/m^3_{WE}	$C_{PTES}(V_{Storage}) = 1\,900 * V_{storage}^{-0.33}$											L	4
Cost function (estimation)	M€/MW_{th}	$C_{PTES}(Q_{\cdot th}) = 0.909 * Q_{\cdot th}^{-0.33}$											M	4
Construction time	months	9	9	8	8	8		7	12	6	12		N	7, 8

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Notes:

A Storage sizes are not limited (e.g. planned Storage for "Big Solar Graz") and depends mostly on requirements like area, cover ratio, etc. Recommended minimum (due to losses) size is: 2 000 m^3 (Ref. 2).
B The specific storage capacity depends on the achieved temperature differences (supply minus return). The value 60 kWh/m^3 equals 50 K and 80 kWh/m^3 60 K (delta T). Higher specific storage capacities up to 90 kWh/m^3 could be reached through further down cooling (e.g. heat pump). Given values are valid for water filled PTES. Using gravel-water capacity will be reduced to 30 - 50 kWh/m^3 (the storage volume for 1 m^3 water equivalent is appr. 1.3 - 2 m^3).
C Efficiency depends on storage period (h,d,w,m). Heat pumps could be used for further discharging (cooling down the storage medium) which increase the storage capacity/efficiency.
D Calculated on monitoring data of the year 2015.
E Depending on temperature levels and operating conditions (weak point is the foil; some manufacturers give warranties till 90 °C; Lifetime could be extended by replacing a new cover).
F As these systems are non-pressurized, maximum operation temperatures results to be lower than 100 °C.
G Although the systems could be designed below 100 °C, in practice they are usually operated between 85 and 90 °C.
H This technology could help to save emissions.
I Based on existing cost developments, a reduction of 10 - 20 % (2020 - 2050), caused by replication of pits, pipes, pumps, heat exchangers and control system, could be estimated. Nevertheless, no resilient learning rate is known.
J Given CAPEX estimation (2015-2050) is based on a 100 000 m^3_{WE} ($\hat{=}$ 10 MW_{th}) PTES and considers the storage incl. interconnection. According to Ref. 11, no significant economy-of-scale for store volumes above 50 000 m^3 is seen. The marginal investment cost for increasing the volume is approximately 20 EUR/m^3.
K Data of Solites as there exists no explicit monitoring of fixed and variable O&M costs for pilot plants. Numbers are valid for the operating time after commissioning and the adjustment and initial optimization of the process control and instrumentation technology.
L Formula is based on given reference and adjusted with costs of realised storages. The cost function could be used in the range from 10 000 to 200 000 m^3_{WE}.
M Given cost formula is converted from EUR/m^3_{WE} in MEUR/MW_{th} assuming a specific heat capacity of 70 kWh/m^3_{WE} and a dis-/charging duration of 700 h (MW = 70 kWh/m^3_{WE} * m^3_{WE} / 700 h / 1 000). Conversion factors are chosen based on the Marstal storage.
N Construction time could be reduced through local conditions (existing excavations e.g. abandoned gravel/sand pit).

7.3.2 Hot water tank storages

Tank storages are mainly used for buffering daily peaks. Moreover they allow to optimize CHP units by decoupling the electric and thermal demand.

Hot water tank storages can be separated into 3 major types:

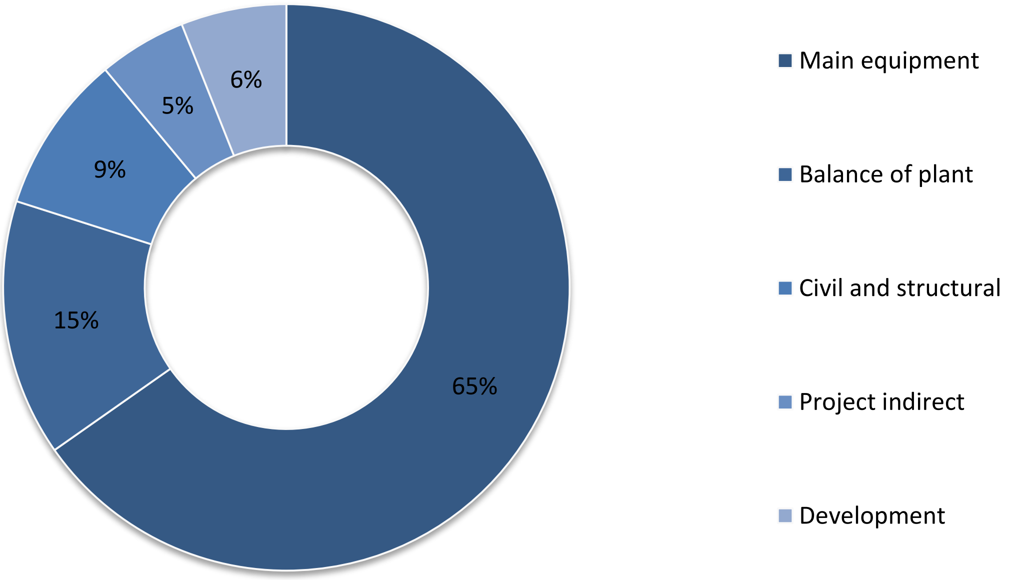
- Unpressurized storages (max. temperature ~ 98 °C)
- 2-zone storages (max. temperature ~ 120 °C)
- Pressurized storages (max. temperature ~ 150 °C)

Relevant for temperature and pressure levels of the storage are the temperature of the main source and the pressure level of the district heating network.

A good empirical formular for designing a heat storage is 50 m³/MW peak load of thermal output. Moreover heat storages are designed for a storage capacity of 5 to 12 h.

The cost components included in the CAPEX estimate for shown below are:

Figure 53: CAPEX breakdown of hot water tank storages



Main equipment consists of the steel tank, the insulation and additional steel structures for O&M (staircases, roof platform)

Balance of plant consists mainly of the compensating reservoir (pressure tanks) or the steam system (2-zone storages or pressurized tanks) and additional piping or charge pumps.

Table 44: Overview of hot water tank storages

	Unit	**2015**	**2020**	**2030**	**2040**	**2050**		**Uncertainty (2020)**			**Note**	**Ref**
A. Energy/technical data								**Lower**	**Upper**			
Heat storage volume	m³	100 – 50 000									A	4, 5
Heat generation capacity	MW	0.4 - 190									B	
Net Storage capacity	MWh	3 – 1 500									C	
Total efficiency, nominal load	%	98	98	98	98	98		97	99		D	
Total efficiency, annual average	%	92	92	92	92	92		91	96		E	2
Electricity consumption	%/MWth	1	1	1	1	1		0	1			
Technical lifetime	years	25	25	25	25	25		20	50			
Steam supply		NA	NA	NA	NA	NA		NA	NA			
Hot water		(o)	(o)	(o)	(o)	(o)		(o)	o		F	
Warm water		o	o	o	o	o		o	o			
Low temperature		o	o	o	o	o		o	o			
B. Environmental data												
CO2	g/MJ										G	
SO2	g/GJ										G	
NOX	g/GJ										G	
CH4	g/GJ										G	
N2O	g/GJ										G	
Particles	g/GJ										G	
C. Financial data												
Quality of CAPEX estimation		medium										
Nominal investment per power output	M€/MW$_{th}$	0.088	0.088	0.088	0.088	0.088		0.072	0.144		H, I	1,3, 4, 5
- of which equipment	M€/MW$_{th}$	0.032	0.032	0.032	0.032	0.032		0.024	0.072			3
- of which installation	M€/MW$_{th}$	0.056	0.056	0.056	0.056	0.056		0.048	0.072			3
Fixed O&M	k€/MW$_{th}$/a	0.4	0.4	0.36	0.36	0.36		0.16	0.8		I, J	
Variable O&M per MWh	€/MWh	NA	NA	NA	NA	NA		NA	NA		K	
X. Technology specific data												
Cost function per thermal power output(estimation)	M€/MW$_{th}$	Invest(x)=(-64*x+184 000)*10^{-6}									M	
Cost function per storage capacity (estimation)	M€/MWh$_{th}$	Invest(x)=(-8.0*x+23 000)*10^{-6}									L	
Nominal investment per storage capacity	M€/MWh	0.011	0.011	0.011	0.011	0.011		0.009	0.018		H, I	1,3, 4, 5
- of which equipment	M€/MWh	0.004	0.004	0.004	0.004	0.004		0.003	0.009			3
- of which installation	M€/MWh	0.007	0.007	0.007	0.007	0.007		0.006	0.009			3
Fixed O&M per storage capacity	k€/MWh/a	0.05	0.05	0.045	0.045	0.045		0.02	0.10		I, J	

References:

1 Technology Data for Energy Plants, Danish Energy Agency , 2012 & 2016
2 Beitrag zur thermodynamischen Analyse und Bewertung von Wasserwärmespeichern in Energieumwandlungsketten, Huhn 2006
3 Construction company information
4 Projects: presurized heat storage Wien Simmering, two zone storages in Nuremberg (33 Tm^3), Duisburg (43 Tm^3), Potsdam (40 Tm^3)
5 Project information 3 000 m^3 pressurized, Germany, 2016

Notes:

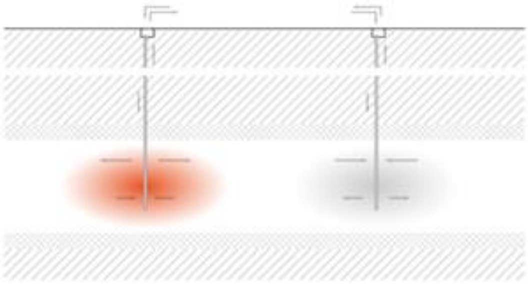
A Biggest known pressure storage tanks are around 6 000 m^3, unpressurized and 2-zone tanks are able of much higher volumes.
B Assumptions: 30 K temperature difference, 12,5% change in total volume per hour
C Assumptions: 30 K temperature difference, 15% unused storage volume (separation layer, volume below (above) inlet diffusors)
D External heat losses ~ 2% (calculation in accordance to AGFW FW 313 and translated with the following assumption: storage cycle ones a day, 90/60 °C, outdoor temperature 10 °C)
E Also includes internal heat losses ~ 5% (exegetic losses due to temperature movement in the separation layer or external losses within the compensating reservoir (when having a pressure storage))
F Higher temperature difference in this systems will lead to higher capacities but due an higher overpressure and following 2014/68/EU requirements investment cost are much higher
G Environmental impacts depends on how the used thermal power was produced
H Price basis net storage capacity. Valid for unpressurized and 2-zone storages, additional invest for pressurized storages: +20 to 40% (depending on pressure level, 40% appr. at + 10 bar)
I Cost basis relates to bigger tanks (30 Tm^3), smaller tanks (100 m^3) apr. 200% higher
J Pressurized tanks need periodic test from testing authorities, costs of apr. 10 T€/storage/a are not included
K Variable O&M mainly depending on temperature losses/ cost of stored thermal energy
L x…Heat storage capacity [3 MWh_{th} … 1 500 MWh_{th}]
M x…Heat storage output [1 MW_{th} … 200 MW_{th}]. Conversion between storage heat capacity and power output: full discharge of the storage in 8 h

7.3.3 Aquifer thermal energy storages

Some locations have geologically good conditions to use aquifers to store thermal energy. An aquifer thermal energy storage (ATES) is an underground thermal energy storage (UTES) technology which could be used as a temporary or as a seasonal storage of cold and heat. Generally this thermal energy storage performs at very low temperatures and the thermal energy accumulated cannot be used directly. The aquifer is accessed by at least two wells (an injection and extraction, or hot and cold well) or multiples of two wells (typically) and screened in the same groundwater aquifer. There is no groundwater consumption as it circulates in a loop. ATES systems have start-up times of 2 to 5 years to reach the normal operating conditions. During this time the underground around the seasonal storage has to be heated up, which causes higher losses than in the long-time operation. That means, that the system efficiency is lower in the first years of plant operation than after.

Although there exist some temporary ATES systems for heat / cool utilizations, only one ATES is designed as a seasonal storage for a district heating system. This plant is located in Rostock, Germany and was built in 2000 as a pilot project. The maximum temperature of the storage is limited to 50 °C as higher temperatures may cause a change of the ground water chemistry. Such storage types cannot be thermally insulated against the surroundings. Hence, heat storage at high temperatures (> 50 °C) is normally only efficient for large storage volumes (more than 20 000 m³ of ground volume) with a favourable surface to volume ratio. The concept of Rostock uses also a heat pump with the storage as source. As the ATES is limited for charging/discharging capacities, a buffer storage as hydraulic separation is used which allows different flows. Furthermore, these storage types are subject to higher requirements for the local subsoil as well as to the approval procedures.

Figure 54: Construction concept of aquifer thermal energy storages (ATES)



Source: Solites

The cost structure is based on the ATES of Rostock, Germany. The category “Main equipment” includes the drilling, the expansion of the wells, the well construction, etc. BOP mainly consists of the charging/discharging devices which includes the protective gas system as well as the underground pipelines and the system technology of the storage circuit in the heating station. As special requirements for materials and installations occur due to the thermal water circuit, the connecting pipes to the heating station and the plant engineering in the heating station are included in the aquifer heat storage, although they are not directly connected to the storage structure.

Figure 55: CAPEX breakdown of aquifer thermal energy storages (ATES)

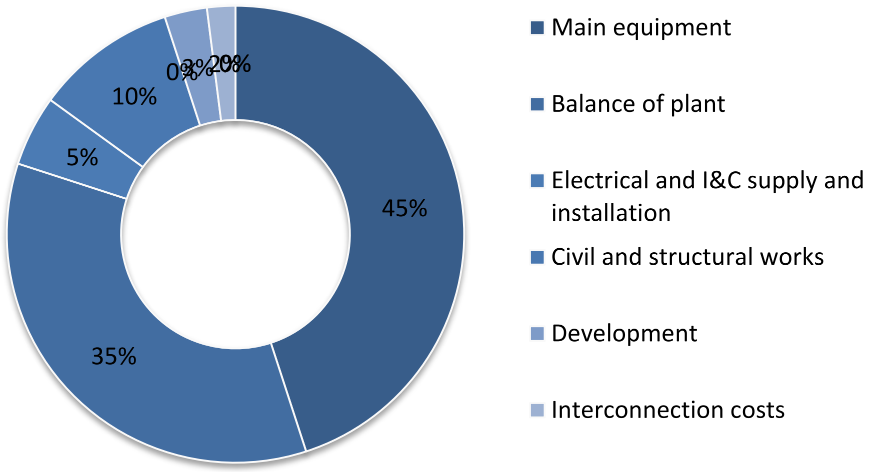


Table 45: Overview of aquifer thermal energy storages (ATES)

	Unit	**2015**	**2020**	**2030**	**2040**	**2050**		**Uncertainty (2020)**		**Uncertainty (2050)**			**Note**	**Ref**
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Heat storage volume (water equivalent)	m^3_{WE}	1 000 - 20 000											A	1
Storage capacity	kWh/m³	30 - 40						60	80	60	80		B	2, 3
Efficiency, annual average	%	40 - 60						30	70	35	75		C	2, 4, 5, 6
Electricity consumption	$\%/MWh_{th}$	3	3	3	3	3		2	5	2	5		D	
Technical lifetime	years	35	35	40	40	45		30	40	35	>45		E	7
Steam supply		N/A	N/A	N/A	N/A	N/A							F	8
Hot water		N/A	N/A	N/A	N/A	N/A								
Warm water		N/A	N/A	N/A	N/A	N/A								
Low temperature (up to 50 °C)		o	o	o	o	o		o	(+)	o	(+)		G	9
B. Environmental data														
CO2	g/MJ_{th}	0	0	0	0	0							H	
SO2	g/GJ_{th}	0	0	0	0	0								
NOX	g/GJ_{th}	0	0	0	0	0								
CH4	g/GJ_{th}	0	0	0	0	0								
N2O	g/GJ_{th}	0	0	0	0	0								
Particles	g/GJ_{th}	0	0	0	0	0								
C. Financial data														
Quality of CAPEX estimation		low												
Learning rate	%												I	2, 10
Nominal investment	$M€/MW_{th}$	1.8	1.8	1.76	1.72	1.70		1.0	4.0	0.8	3.5		J	1, 10, 11
- of which equipment	$M€/MW_{th}$	0.54	0.54	0.53	0.52	0.50		0.36	0.72	0.34	0.68		K	11
- of which installation	$M€/MW_{th}$	1.26	1.26	1.23	1.20	1.20		1.08	1.44	1.02	1.36			11
Fixed O&M	$k€/MW_{th}/a$	1.8	1.8	1.7	1.7	1.7		1.3	3.6	1.2	3.5		L	11
Variable O&M excl. electricity costs	$€/MWh_{th}$	N/A	N/A	N/A	N/A	N/A								11
X. Technology specific data														
Cost function (estimation)	$€/m^3_{WE}$	$C_{ATES}(V_{Storage}) = 9\,747 * V_{storag}^{-0.57}$											M	11
Cost function (estimation)	$M€/MW_{th}$	$C_{ATES}(Q_{\cdot th}) = 0.744 * Q_{\cdot th}^{-0.57}$											N	11
Construction time	months	4	4	3	3	3		3	8	2	5		O	1

References:

1 Saisonalspeicher.de - Das Wissensportal für die saisonale Wärmespeicherung; online available: http://www.saisonalspeicher.de/
2 Seasonal thermal energy storage; IEA SHC Task 45 Large Systems, June 2015
3 Seasonal Ground Solar Thermal Energy Storage - Review of Systems and Applications; Pavlov, G. K., & Olesen, B. W., 2011
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5 A Life Cycle Cost Analysis of Large-scale Thermal Energy Storage Technologies for Buildings using Combined Heat and Power; K. Gaine, A. Duffy, July 2010
6 Underground Thermal Energy Storage; Kun Sang Lee, 2013 (© Springer-Verlag London)
7 The Central Solar Heating Plant with Aquifer Thermal Energy Store in Rostock - Results after four years of operation; Solites, June 2004
8 Status and recommendations for RD&D on energy storage technologies in a Danish context; Danish Energy Authority (EUDP and Green Labs DK), Energinet.dk (ForskEL and ForskVE), Danish Council for Strategic Research, Danish Energy Association (ELFORSK), February 2014
9 Solar district heating guidelines - Storage; Solites, August 2012
10 Technology Data for Energy Plants; Danish Energy Agency and Energinet.dk, May 2012
11 Technisch-wirtschaftliche Analyse und Weiterentwicklung der solaren Langzeit-Wärmespeicherung; Solites, 2012

Notes:

A Plant of Rostock (DE) with 20 000 m³ soil accumulation (equals 5 000 m³ water equivalent) and two well drillings with each 30 m depth. The aquifer layer is situated in a depth of 15 – 30 m below ground surface and the fountain productivity in each case is 15 m³/h. Storage sizes are not limited itself and depends mostly on requirements like geothermal and ground conditions, cover ratio, etc. Recommended minimum (due to losses) size is: 1 000 m³ (Ref.2). Geological requirements are: Natural aquifer layer, high hydraulic conductivity, confining layers on top and below, no or low natural ground water flow, suitable water chemistry at high temperatures (Ref. 3).

B Storage volume for 1 m³ water equivalent: 2 - 3 m³.

C Efficiency depends very on geological structure and temperature levels. Heat pumps could be used for further discharging (cooling down the storage medium) which increase the storage capacity/efficiency. Storing higher temperatures, thermal losses through the bedrock, the sides and the top soil become more significant.

D Assumed electrical consumption including pumping effort for the drillings.

E Life time for the ATES in Rostock was assumed with 40 years. Attention: life time depends very on time-limited permits from authorities. Life time of other components (e.g. pumps, piping, etc.) is very depending on the groundwater chemistry.

F According to Ref. 8, ATES-systems above 50 °C operating temperatures are named HT-UTES (high-temperature underground thermal energy storage). For high temperature storage, above 100 °C, deeper wells of over 200 m are needed in order to reduce heat losses. This has a significant impact on the cost of the project and needs to be examined closely (Ref. 5). In Europe, only one demonstration project with HT-UTES in a deep reservoir (> 1 000 m) is known at Neubrandenburg (DE). In this plant, HT-UTES is performed in the approx. 1 250 m deep Upper Postera sandstone reservoir. The project was initiated in 2004, and hot water of 80 °C is stored in the reservoir which has a virgin temperature of 55 °C. Worldwide, only one other commercial HT-UTES project with storage temperatures > 60 °C exist at the "Reichstag" building in Germany (Ref. 8).

G ATES storages are designed for a maximum temperature of 50 °C in order to reduce the heat losses and to avoid water treatment. The storage in Rostock is designed for 50 °C supply and 30 °C return temperature. Although, monitoring values from 2002 that shown that the design values were not reached (supply: 44 °C, return: 36 °C).

H This technology could help to save emissions.

I Based on existing cost developments, a reduction of 5 - 20 % (2020 - 2050), caused by replication of exploitation, pipes, pumps, heat exchangers and control system, could be estimated. Nevertheless, no resilient learning rate is known.

J CAPEX estimation is done for a 5 000 m^3_{WE} (≙ 0.21 MWth) ATES based on the combined cost curve for BTES & ATES (€/m³) given in Ref. 11. Cost estimation is converted from €/m^3_{WE} in MEUR/MW_{th} based on an assumed specific heat capacity of 30 kWh/m^3_{WE} (planned value of the plant in Rostock) and a dis-/charging duration of 700 h (same assumption like PTES) (kW = 30 kWh/m³WE * m³ / 700 h).

K Cost allocation is done based on the ATES plant in Rostock.

L Data of Solites as there exists no explicit monitoring of fixed and variable O&M costs for pilot plants. Numbers are valid for the operating time after commissioning and the adjustment and initial optimization of the process control and instrumentation technology.

M Formula is adapted of the given reference. The cost function could be used in the range from 1 000 to 20 000 m^3_{WE}.

N Given cost formula is converted from EUR/m^3_{WE} in MEUR/MW_{th} assuming a specific heat capacity of 30 kWh/m^3_{WE} and a dis-/charging duration of 700 h (MW = 70 kWh/m^3_{WE} * m^3_{WE} / 700 h / 1 000).

O Construction time depends mostly on geological conditions and needed drilling effort. Geological survey and official approvals could be estimated with extra 6 - 8 months in advance.

7.3.4 Phase change material storages

Phase change material (PCM) storages (also known as latent heat storages) utilize the enthalpy of thermodynamic changes of a medium. The principle most frequently used is the utilization of the phase transition solid-liquid and vice versa.

The advantage of latent heat storage as opposed to sensitive heat storage is its high storage density by storage and removal at the same temperature level. Further advantage is the wide range of melting temperatures as well as the higher storage capacity. Latent heat storage systems therefore require significantly less space. On the contrary, in most cases, the PCM has a very poor thermal conductivity in the liquid as well as the solid state. For the improvement of heat transport, e.g. Aluminium ribs are used. Comparatively high costs are the biggest disadvantage.

Depending on the utilization, different storage designs and materials are required. For DH applications, most promising materials are HDPE (high-density polyethylene) and paraffins. Whereas the HDPE (melting point at 110 – 130 °C) could be an alternative to pressurized water storages and parrafins for applications between 40 – 90 °C. In DH systems the PCM stores can be used for smoothing load peaks, network expansions and having smaller storage in substations.

At the moment no PCM storage in a DH grid is known, but some pilot activities are ongoing (e.g. one DH operator in Austria is thinking about to install one but the decision is still open). That is why, the given figures below have low accuracy and mostly depend on estimations and expectations.

The given cost breakdown structure below is also based on own estimations. The biggest costs occur through the storage itself. The main equipment consists of material for the shell-and-tube heat exchanger, the thermal oil and the PCM. The shell-and-tube heat exchanger consists of steel tubes containing the PCM, the container and the baffles. The minor costs will occur due to installation on-site.

Figure 56: CAPEX breakdown of phase change material storages

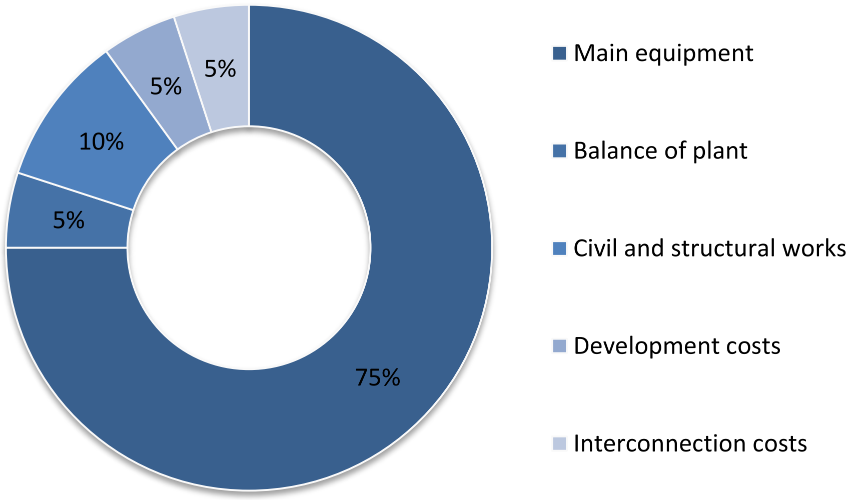

Table 46: Overview of phase change material storages

	Unit	2015	2020	2030	2040	2050		Uncertainty (2020)		Uncertainty (2050)			Note	Ref
A. Energy/technical data								**Lower**	**Upper**	**Lower**	**Upper**			
Thermal power	MW$_{th}$	0.001 >>											A	1, 2
Efficiency	%	>95											B	1, 2, 3
Electricity consumption	%/MWh$_{th}$	1											C	
Technical lifetime	years	10 - 30+											D	1
Steam supply		possible											E	4
Hot water		possible												
Warm water		possible												
Low temperature		possible												
B. Environmental data														
CO2	g/MJ$_{th}$	0											F	
SO2	g/GJ$_{th}$	0												
NOX	g/GJ$_{th}$	0												
CH4	g/GJ$_{th}$	0												
N2O	g/GJ$_{th}$	0												
Particles	g/GJ$_{th}$	0												
C. Financial data														
Quality of CAPEX estimation		low											G	
Learning rate	%												H	
Nominal investment	M€/MW$_{th}$	<0.1 - 1>											I	1, 5, 6, 7
- of which equipment	M€/MW$_{th}$	0.8											J	
- of which installation	M€/MW$_{th}$	0.2												
Fixed O&M	k€/MW$_{th}$/a	N/A											K	1, 5
Variable O&M excl. electricity costs	€/MWh$_{th}$	N/A												
X. Technology specific data														
Storage capacity	kWh$_{th}$/t	50 - 150											L	1, 2, 4, 8
Storage period	h, d, w, m	h - w											M	1, 2, 8
Operating temperature	°C	-50 - >1 000											N	3, 4

References:

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2 Seasonal thermal energy storage; IEA SHC Task 45 Large Systems, June 2015

3 Mobile Fernwärme - Wärmeverwertung durch Mobile Latentwärmespeicher; J.H. Budach, Grazer Enegiegespräche on 23th October 2007

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5 Cost Analysis of Simple Phase Change Material-Enhanced Building Envelopes in Southern U.S. Climates; Jan Kosny, Nitin Shukla and Ali Fallahi (Fraunhofer CSE), January 2013

6 Compact Thermal Energy Storage: Material Development for System Integration; joint task IEA SHC Task 42 and IEA ECES Annex 29, August 2015; (online available: http://task42.iea-shc.org/data/sites/1/publications/Task42-Annex-29-Position-Paper-and-All-Final-Deliverable-Papers.pdf)

7 Experimental characterization and simulation of a hybrid sensible-latent heat storage; C. Zauner et al. (AIT), 2016; (online available: http://www.sciencedirect.com/science/article/pii/S0306261916318451)

8 Thermal Energy Storage; Rainer Tamme, Doerte Laing, Wolf-Dieter Steinmann and Thomas Bauer (Institute of Technical Thermodynamics, Aerospace Center, Stuttgart, Germany), 2013

Notes:

A Due to modular design, almost every size is possible (depends only on the requirements; e.g. like batteries).

B The technology is characterized by low losses, which mostly depends on the insulation (which has no significant influence on the investment costs). The mobile latent heat storage has losses of approx. 0.5 %/24h.

C Pumping, control and regulation cause electricity consumption which is assumed to be low at 1 % (mostly influenced by pumping effort, which depends on the storage design).

D Depending very much on storage design/materials, cycles, temperature and operating conditions.

E Each heat carrier fluid is possible (air too) and therefore a broad bandwidth of temperature applications.

F Depending on the system design, PCM storages could help to save/reduce emissions.

G Cost estimation is very low, as no PCM storage in a DH system is known at the moment.

H Figures could not be provided, but if there is an adequate market need, high cost reductions could happen.

I No resilient investment costs could be provided at the moment as PCM storages are still in the pilot phase. The costs mainly occur through the shell and-tube heat exchanger, the thermal oil and the PCM. Ref. 7: The general trend shows that the material costs per kilowatt-hour decrease upon increasing the tube diameter independent of the ratio of PCM to thermal oil. Furthermore, the cost reduction is larger for storage configurations with larger PCM fractions. Also, increasing the share of PCM reduces material costs per kilowatt-hour which reflects the higher energy density of the PCM. Ref. 5 allows a more detailed view on costs of different phase change materials (like Organic, Inorganic, Salt Hydrates, Biobased and Shape-Stabilized). Ref. 6 includes a table of selected thermal energy storages with specifications of usage, materials and costs.

J Own estimation because no accurate data are known.

K Currently it is not possible to provide reliable information. Nevertheless, the given references quotes operational costs (fixed and variable) of kEUR 230/MW_{th}/a - but this value has to be handled carefully.

L The storage density is approximately twice as large as for water storages.

M PCM storages should be preferred used as short term utilizations as the economical feasibility increases with each dis-/charging process.

N A lot of different materials exist for PCM storage usage. Therefore, the temperature range is very big and could be chosen individually for each case (e.g. very low temperatures in space applications to very high temperatures above 1 000 °C in concentrating solar power plants). In Ref. 3 thermophysical properties are listed for some selected solid to liquid phase-change materials.

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