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14th IAEE European Energy Conference

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Sustainable Energy Policy and Strategies for Europe

October 28-31, 2014 in Rome, Italy
LUISS University of Rome

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ABSTRACT SUBMISSION DEADLINE **JUNE 1st, 2014**

The Conference Objectives

As Europe strives to overcome the economic crisis, energy stands out both as a conditioning factor and as an opportunity. The energy situation is evolving in Europe as well as in the rest of the world, where new actors, the emerging economies, are taking the leading role. Political developments in several areas of the globe (North Africa and Middle East, the Caspian region, ASEAN countries) are reshaping the geopolitical situation, generating some worries about the security of supply in the EU countries.

The crisis has somewhat released the pressure on energy demand and allowed to reach objectives in the reduction of greenhouse gas emissions that seemed out of reach, but as the European Energy Roadmap to 2050 makes clear the objectives for 2020 and beyond are likely to require a renewed, powerful effort as soon as the economy is back on the track.

Important steps towards the establishment of a really open and competitive energy market in Europe have been achieved, but much remains to be done. Energy technologies (as evidenced in the SET-Plan) have evolved and contributed new solutions, as in the case of non-conventional hydrocarbon resources, but this has happened more as gradual step-by-step improvements than by real breakthroughs. The evolution of these technologies has been influenced by the instruments adopted by governments to promote new sources or new solutions rather than directly by market demand. The use of "market instruments" to steer the energy choices in the direction of sustainability is the subject of animated discussions, based on the analysis of diverse case studies. The hope of obtaining reductions of energy costs by these means has been often frustrated.

Some sectors show difficulties in moving in the right direction (in terms of economy as well as sustainability): the outstanding example is the transport sector, where, apart from the improvement of the efficiency of vehicles, there is little sign of moving from the present paradigm (with private prevailing over public transport, road over track and waterways,) and sporadic attempts are done to reduce the need of displacements (both of people and of goods). Another sector which is meeting institutional rather than technical difficulties is the building sector, especially as concerns distribution of costs and revenues among the different actors.

The first (dual) plenary session of the Conference will be devoted to the European Energy Road Map to 2050, and to the response to environmental challenges.

The next plenary sessions will deal with the specific energy aspects of transportation, and to the efficiency of energy utilisation in buildings. The last two plenary sessions will be devoted to energy geopolitics and emerging countries, and to the regulation of energy markets.

The 14th IAEE Conference will try to discuss all the issues related to European policy and its new perspectives in 8 plenary and 40 concurrent sessions that will be organized by the **AIEE- Italian Association of Energy Economists and IAEE - The International Association for Energy Economics**, in cooperation with the **Guido Carli Free International University for Social Studies - LUISS**, that will host this conference.

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Reach a 20% CO_2-reduction at no extra costs with a cost-minimizing investment and dispatch model to cover the combined electricity and heat demand for the region of Vienna

Richard Büchele, Vienna University of Technology, Energy Economics Group,
Gusshausstrasse 25-29, A-1040 Vienna, Fax: +43 1 58801/370397,
Tel.: +43 1 58801/370368, buechele@eeg.tuwien.ac.at
Reinhard Haas, Vienna University of Technology, Energy Economics Group
Michael Hartner, Vienna University of Technology, Energy Economics Group

1. Introduction

The main part of our today's energy supply systems has grown over time and still contains old facilities. New technologies using renewable forms of energy are installed step by step and mix up with depreciated assets. This makes it impossible to build the optimal composition of a supply system from scratch. Nevertheless an increasing number of national and international policy agreements and respective targets require a cost-efficient and environmentally friendly energy supply. In addition to the use of alternative forms of energy, the coupling of electricity and heat supply can make an essential contribution to achieve this.

In this paper we present a mixed integer optimization model to evaluate cost effective options to reduce the CO_2 emissions of a region with district heating focusing on modelling combined heat and power plants (CHP). The model is applied to the case of the city of Vienna, Austria, for which results are shown at the end of this paper.

Within the last decades more and more researches concerned about how to model these CHP units and how to solve the economic dispatch problem (e.g. Chapa and Vega Galaz, 2004; Geem and Cho, 2012; Halldorsson, 2003) and further studies were carried out integrating different renewable- or non-renewable technologies into a CHP system (Lund and Münster, 2003). Some of them concentrated on the power market only, some of them focused on integrating one special technology, others on how to supply residential building etc.

So there are many individual models to highlight special considerations. On the other hand various energy planning tools (multi-purpose models) which are used for a wide range of different studies are also available as reviewed in (Connolly et al., 2010). Probably the best known are MARKAL/ TIMES (Rath-Nagel and Stocks, 1982), HOMER, IKARUS (Markewitz et al., 1996), RETScreen and PRIMES. Another widly used model is the EnergyPlan (Lund, 2014) model which is used for a lot of different case studies in various countries. In contrast to the model presented in this paper, EnergyPlan is aggregated in its system description and not each individual station and component is described. Furthermore EnergyPlan optimizes the operation of a given system and does not optimize investments in the system but it also analyses one year in a 1 hour time resolution. Another powerful model used for a wide range of purposes and investigating many different technologies to cover the heat and electricity demand for a countrywide area is the HiREPS model implemented at the Vienna University of Technology (Totschnig, 2013). Like the model applied in this study, it optimizes the composition of the overall system to cover a given heat and electricity demand by investing in cost-efficient technologies. In contrast to the HiREPS, this model focuses on one single district heating system within a small region like a city. Furthermore it contains an existing stock of depreciated technologies and allows for investments in new technologies. With this model we aim at assessing the possibilities to minimize the costs of an existing energy supply structure containing depreciated assets by investing in new technologies and optimal scheduling of all units. This is done using an investment and dispatch optimization model once without additional restrictions and once with a required 20% CO2-reduction compared to the actual installed structure. In this study we show that this reduction is achievable at no extra costs.

2. Methodology

A cost minimizing investment and dispatch model based on a mixed integer linear program is developed for this study. To represent the demand side one hourly load profile based on final energy data is created for electricity- and one for heat-demand for an entire year. The structure of the modelled energy supply system and the implemented technologies will be explained in the following subsection.

2.1. Structure of the Model

The model represents a region supplied by a structure as shown in Figure 1. There is one electricity demand and one thermal demand that have to be covered in each hour (8760h). To cover the thermal demand the region is partly (or totally) supplied by a district heating (DH) system with fixed size of grid infrastructure. The remaining part is provided by decentralized technologies. The model offers a detailed representation of the supply side covering all currently installed central plants of a region with their individual parameters. The decentralized heat-technologies taken into account in this study are: gas boilers, heat pumps (HP) and solar-thermal collectors (ST). The implemented central heat-technologies are: an electrical boiler also called power to heat (P2H), district heating plants (DHP), heat storage (HS) and four different types of combined heat and power (CHP) units (gas turbine (GT), backpressure steam turbine (BPST), extraction steam turbine (EXST) and combined cycle (CC) units) with three different fuel types (residual waste, biomass and natural gas). Each CHP unit is modelled with individual technological parameters explained in subsection 2.3. The electrical demand of the region must be covered by the output of the CHP units, the renewable technologies wind turbine generators (WTG) and photovoltaic (PV) cells and additionally the possibility of importing and exporting electricity on the spot market of the European energy exchange (EEX) is given.

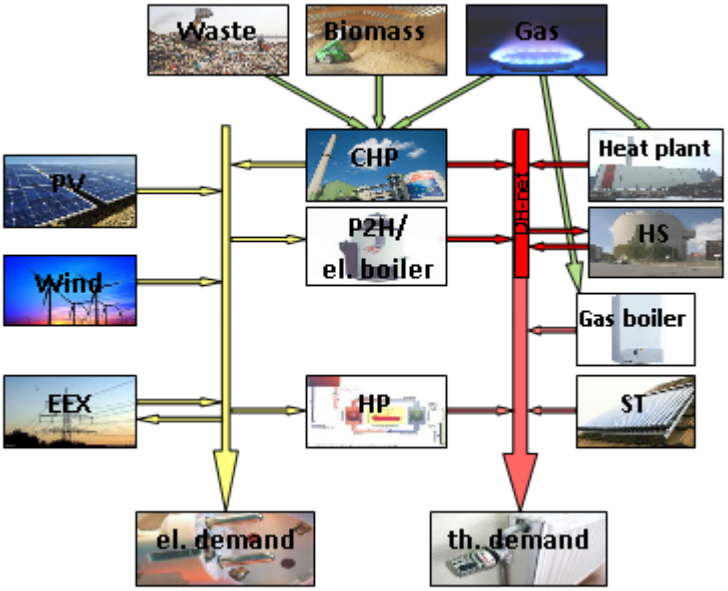

Fig. 1: Structure of the model

2.2. Modelling of energy demand

To model the electrical and thermal load profiles a top-down approach is used. The annual electrical and thermal final energy consumption is used to generate one hourly load profile for the electrical demand and one to represent the thermal demand.

Electrical demand: The electrical demand profile is calculated by using eleven different profiles to represent the different sectors households, the service sector including industrial sector, and the agricultural sector. These profiles are available for three different periods of the year (summer, winter and transition period) and for three different types of weekdays per period (Workday, Saturday and Sunday). So every category has nine different daily profiles in a 15 minutes time resolution. The profiles for typical days of the different sectors are transformed into yearly profiles and multiplied with the respective demand of the sectors. To get an hourly load profile the mean of the four quarter hour values is calculated.

Thermal demand: The thermal load profile is constructed in a similar way. Thermal profiles are available in 1 hour resolution for different regions and the following categories.

- Old and new single family house
- Old and new multi-family house
- Service sector; Accommodation sector, Commerce
- Restaurants, Banks, Bakeries, Laundries

These profiles are used to generate one hourly thermal load profile representing the total heat demand (including space heating and hot water) of the modelled area. It is assumed that the load profiles are identical within the district heating area and the area supplied by local technologies.

Demand constraints

All demand constraints have to be fulfilled for every hour of the year. The thermal demand constraint consists of two parts, one representing the demand within the DH area and the other representing the area supplied by the distributed technologies. Within the DH area the sum of the generated heat from the central technologies (all CHP units, heat plants, heat storage and the P2H unit) has to compensate the losses of the DH grid and has to be greater than or equal to the demand within the supplied area. DH_{share} is the share of the total heat demand that is provided by the DH grid. This is a fixed value but can also be calculated in the optimization if modelled as a variable.

$$\left(\sum_i q_i[t] + q_{HS}[t] + q_{P2H}[t]\right) * (1 - Loss_{net}) \ \geq \ DH_{share} * d_{th}[t]$$

Outside of the DH area the sum of the produced heat from the local technologies (gas boiler, heat pump (HP) and solar collector (ST)) has to be greater than or equal to the share of heat demand not supplied by the DH system:

$$q_{HP}[t] + q_{boiler}[t] + q_{ST}[t] \geq (1 - DH_{share}) * d_{th}[t]$$

The electrical demand constraint says that the production of all CHP units plus traded electricity has to be greater than or equal to the overall electricity demand plus the electricity consumption of the HP and the P2H minus the electricity produced by photovoltaic and wind turbine generators:

$$\sum_i p_i[t] + EEX[t] \geq \ d_{el}[t] + \frac{q_{HP}[t]}{COP_{HP}} + \frac{q_{P2H}[t]}{\eta_{P2H}} - p_{PV}[t] - p_{wind}[t]$$

2.3. Modelling of supply technologies

The model allows for detailed implementation of all central units supplying the district heating system. Especially the differences in combined production of heat and power are modelled according to the technological facts.

Modelling of CHP Units

Four different types of CHP units are modelled. Every type has an individual so called “production region” that shows all possible combinations of combined heat and power production. The different implemented types are:

- Backpressure steam turbine (BPST)
- Extraction steam turbine (EXST)
- Gas turbine with heat recovery (GT)
- Combined cycle turbine with heat extraction (CC)

Figure 2 shows the borders of the modelled regions for allowed combinations of heat and power production for all of the four different technologies and the expressions describing these borders.

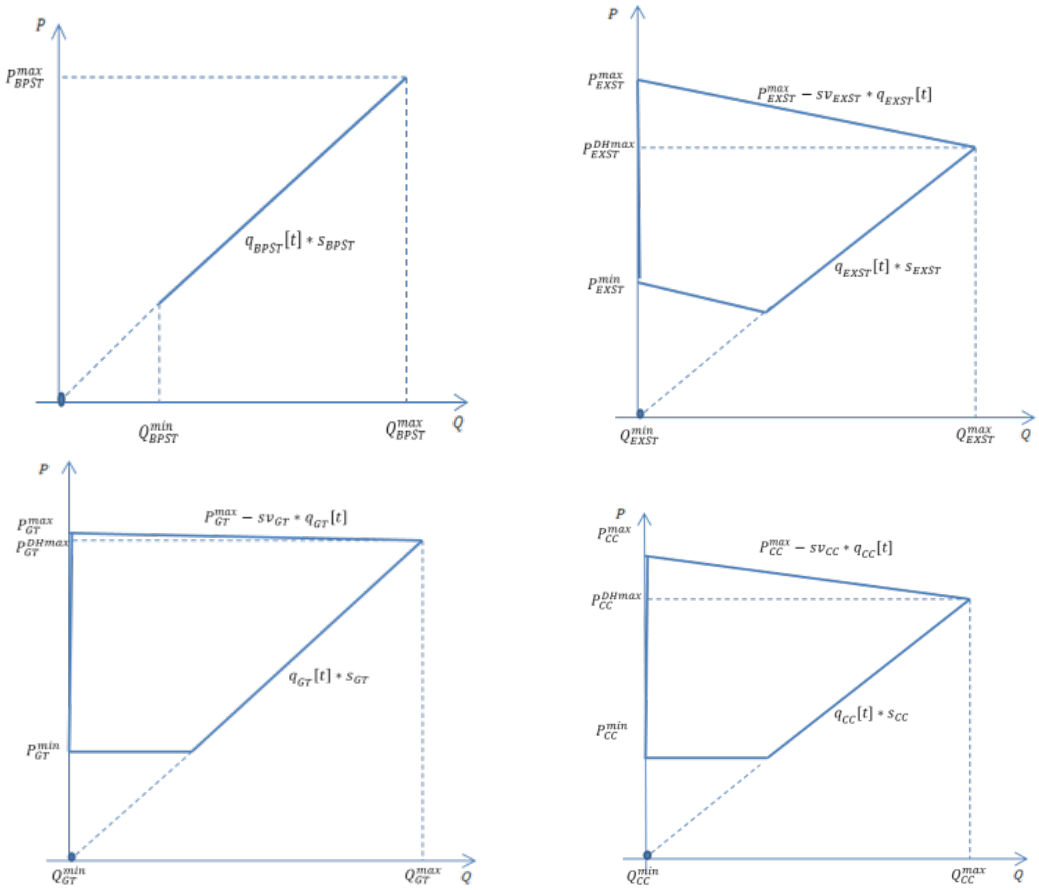

Fig. 2: Regions of allowed combined production for BPST, EXST, GT and CC

All of these technologies are characterised by the following parameters:

- Thermal net production (q_i): Heat output of unit that is feed into the DH grid
- Electrical net production (p_i): Electrical output that is used to cover electrical demand or can be exported
- CHP coefficient (s_i): Power-to-heat ratio when extracting the maximum thermal power
- Electricity loss: (sv_i) Decrease in produced electricity of an extraction unit when extracting heat at a given fuel consumption
- Efficiency (electrical, thermal or total) (η_{el}, η_{th}, η_{tot}): Ratio of net production (of electricity, heat or sum of heat and electricity) to used fuel.
- Marginal costs: costs to produce an additional unit of energy. Including here only fuel costs and emission certificates costs
- Loss of efficiency: Additional costs due to decreased efficiency when unit is not operated at full load (optimal load)
- Start-up restrictions: CHP units have to be switched on for some consecutive hours after their start up due to thermodynamic conditions
- Start-up costs: costs to switch on CHP and heat plants. Including extra fuel consumption and emission-costs for start-up and wear and tear costs

Other technologies

Other central heat technologies within the DH area are heat plants, an electrical boiler (power to heat) and a heat-storage to decouple heat and electricity production.

- The district heating plants are modelled as simple technology that can produce within their minimal and maximal boundaries with additional start-up costs and loss of efficiency at part load.
- The P2H unit can produce thermal power up to the installed capacity and does increase the electrical demand according to its efficiency.
- The heat storage is modelled as a storage that can be loaded or unloaded up to a maximum load power within its minimal and maximum capacity. Additionally there is a little loss when charging or discharging and an hourly loss of stored energy.

Local heat technologies are solar collector, gas boiler and heat pump.

- The solar collector is modelled with constant efficiency throughout the year but a thermal output depending on the angle of the sun and the hourly radiation.
- To represent a technology applicable also in cities the heat pump is modelled as air-source heat pump with a coefficient of performance (COP) depending on the outdoor temperature while the indoor temperature is assumed to be constant. The potential for ground-source or water-source heat pumps may be very limited in urban areas. It is assumed that the heat pump is a compression heat pump and therefore also increases the electrical demand according to the actual COP
- The gas boiler is implemented as simple technology that converts natural gas into heat at high efficiency. The production costs contain the price for the input gas and also include the CO2 certificates.

Technologies to cover the electrical demand only are photovoltaic cells, wind turbine generators and a transmission line to import or export on the EEX.

- The PV cells are modelled similar to the solar collector with constant efficiency throughout the year but el. power output depending on the angle of the sun and the hourly radiation.
- The WTG is modelled as one type with standard height and one underlying performance characteristic. The power output only depends on the hourly wind speed.
- Exchanges on the transmission line are possible up to a limited capacity. It is assumed that there are no losses.

Investments

All actual installed capacities are assumed to be fully depreciated and do not account for any capital costs. Following capacities can be installed:

- Additional area of PV cells
- Additional area for solar collector
- Additional thermal power output of heat pump
- Additional wind turbine generators
- Additional thermal power output of P2H unit
- Additional thermal power output of gas boiler
- Additional capacity of heat storage
- Extend storage power of the heat storage

2.4. Objective function

The objective function of the model is a cost minimization of the overall system costs. The costs consist of start-up costs of the CHP units and the heat plants, production costs including fuel, efficiency loss and emission certificates for all technologies using fossil fuels, annualized investment costs of additional capacities and costs and surplus of electricity trade.

$$min \sum (c^{startup} + c^{production} + c^{invest} + c^{trade})$$

The start-up costs: $c^{startup} = \sum_{i,t} \left(c_i^{startup} * up_i[t] \right)$

Production costs: $$c^{production} = \sum_{i,t} \begin{pmatrix} c_i^{offset} * on_i[t] \\ c_{EXST,GT,CC}^{mc} * \frac{p_{EXST,GT,CC}[t] + sv_{EXST,GT,CC} * q_{EXST,GT,CC}[t]}{\eta_{el}} \\ c_{BPST}^{mc} * \frac{(1+s_{BPST}) * q_{BPST}[t]}{\eta_{ges}} \\ c_{DHP}^{mc} * \frac{q_{DHP}[t]}{\eta_{th}} \\ c^{boiler} * \frac{q_{boiler}[t]}{\eta_{boiler}} \end{pmatrix}$$

Investment costs: $$c^{invest} = \sum \alpha * \begin{pmatrix} A_{PV}^{add} * c_{PV}^{inv} + A_{ST}^{add} * c_{ST}^{inv} \\ Q_{HP}^{add} * c_{HP}^{inv} + Q_{P2H}^{add} * c_{P2H}^{inv} + Q_{boiler}^{add} * c_{boiler}^{inv} \\ Q_{HS}^{add} * c_{HS_Q}^{inv} + cap_{HS}^{add} * c_{HS}^{inv} \\ N_{wind}^{add} * c_{wind}^{inv} \end{pmatrix}$$

Electricity trade: $c^{trade} = \sum_t c^{EEX}[t] * EEX[t]$

2.5. CO2- Emissions

The CO2 Emissions are calculated as overall Emissions of the system. Therefore no allocation of the respective emissions for heat and electricity is needed. For the imported and exported electricity the emission factor of the European electricity mix is used. Also the local technology of gas boiler adds to the CO2 emission of the supply system. The emissions of the different CHP technologies are calculated according to their fuel input.

3. Data and calibration of the model

In this section the used data for the calibration of the model is presented. The modelled region represents the city of Vienna which has a district heating net that covers approx. 36% of the thermal demand. Although for some values newer data would have been available the year 2010 has been chosen as data year to get consistent Data.

3.1. Demand Data:

The data to generate the electrical and thermal load profile is based on the "Energiebericht der Stadt Wien 2012" (Haas et al., 2012). In this report the annual electrical and thermal final energy consumption is split into the different sectors according to the national energy statistics. These energy data is corrected by the output of technologies not considered in this model like the hydro-electric power stations or shares held in power stations not within the modelled region. The remaining demand of the different sectors is assigned to the respective load profiles. Figure 3 shows the sectorial shares of thermal and electrical final energy consumption in Vienna in 2010.

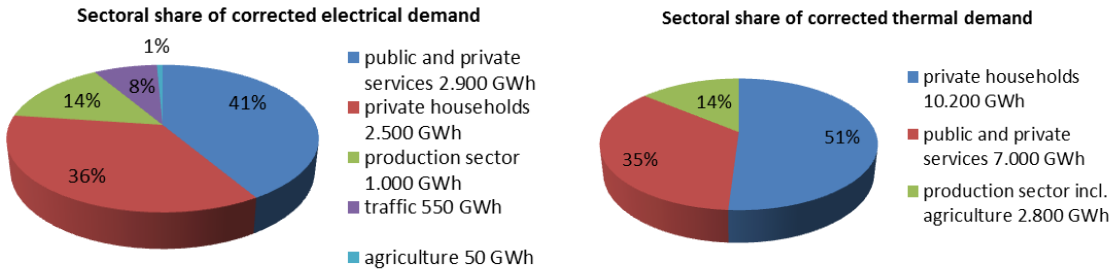

Fig. 3: Shares of sectorial demand for Vienna 2010

3.1. Technical Data:

In Vienna there are six different CHP plants, four waste incineration plants and five district heating plants supplying the district heating system. All of them are modelled with individual parameters.

CHP plants

Five of the CHP plants use mainly natural gas and one uses biomass as an energy carrier. All of these plants are modelled as one of the four CHP types described in previous section. The used technical data come from the report "Optimierung und Ausbaumöglichkeiten von Fernwärmesystemen" (Böhmer, 2009). For missing data assumptions are made based on studies from Gatzen, (2004) and Schröder et al., (2013):

- Efficiency losses of gas turbines at minimum load are approx. 20% of maximal efficiency. Minimum load is 20% of the maximum capacity.
- Efficiency losses of steam turbines at minimum load are approx. 5 to 10% of maximal efficiency. Minimum loads range from 40 to 60% of maximum capacities.
- Efficiency losses of combined cycle plants are approx. 10 to 13%% of maximal efficiency at minimum loads of 30 to 35%

According to (Ellersdorfer et al., 2008) to calculate the start-up costs and time we use:

- Start-up time of gas turbines approx. 0.5 hours
- Start-up time of Extraction steam turbines approx. 1 hour
- Start-up time of serial CC turbines is the sum of the individual start up times
- Minimum on-time for all CHP units is 3 hours (minimum pause time is not used)

Table 1 shows the parameters of the CHPs:

Plant Name	Type	P_{max}	P^{FW}_{max}	P_{min}	Q_{max}	Q_{min}	η_{el_max}	η_{ges}	η_{min}	t_{start}	c_{start}
		MW_{el}	MW_{el}	MW_{el}	MW_{th}	MW_{th}	-	-	-	h	€
Simmering 1	CC	820	700	150	450	0	57%	-	42.6%	2	53.947
Simmering 2	GT	65	63	13	150	0	27%	-	21.6%	0.5	4.062
Simmering 3	CC	420	365	126	350	0	43%	-	36.6%	1.5	29.913
Donaustadt	CC	400	350	120	250	0	58%	-	49.3%	1.5	21.121
Leopoldau	BP ST	140			170	59.5	-	82%	71.3%	0.5	6.380
Simmering bio	EX ST	24	16	9.6	35	0	36%	-	32.4%	1	1.333

Tab. 1: Parameters of the CHPs

Waste incineration plants

Three out of the four waste incineration plants also work as CHP's and are modelled as backpressure steam turbines. Only the incineration plant "Floetzersteig" does not produce electricity and therefore is modelled as district heating plant. General assumptions for the incineration plants are:

- Incineration plants do have minimum loads of 80% of their maximum load to reach afforded temperatures and emission values
- Efficiency loss is 15% at minimum load of 80%
- It is assumed that there is no co-firing with other fuels

Table 2 shows the parameters of the waste incineration plants

Plant Name	Type	P_{max}	Q_{max}	Q_{min}	η_{th}	η_{min}	t_{start}	c_{start}
		MW_{el}	MW_{th}	MW_{th}	-	-	h	€
Spittelau	BP ST	6	60	48	78%	66.3%	2	3.173
Pfaffenau	BP ST	11	50	40	76%	64.6%	2	3.010
Simmering	BP ST	9	75	60	70%	59.5%	2	4.500
Flötzersteig	DHP	-	50	40	81%	68.9%	2	2.315

Tab. 2: Parameters of the waste incineration plants

District heating Plants

Most of the district heating plants in Vienna are used for peak load coverage in winter and as back-up in case of blackout of the CHPs. General assumptions for the district heating plants are:

- Minimum load is 10%
- Efficiency loss 5% at minimum load
- Start-up time is 0.5h

Table 3 shows the parameters of the district heating plants

Plant Name	Type	Q_{max}	Q_{min}	η_{th}	η_{min}	t_{start}	c_{start}
		MW_{th}	MW_{th}	-	-	h	€
Spittelau	DHP	400	40	89%	84.6%	0.1	5.056
Arsenal	DHP	325	32.5	90%	85.5%	0.1	4.108
Kagran	DHP	175	17.5	88%	83.6%	0.1	2.262
Inzersdorf	DHP	340	34	90%	85.5%	0.1	4.114
Leopoldau	DHP	170	17	90%	85.5%	0.1	2.102

Tab. 3: Parameters of the district heating plants

Other technologies

In Table 4 the actually installed capacities, the efficiencies and the maximum potential for additional investments of the other technologies are shown.

Technology	installed capacity	Efficiency	Potential
Air Source Heat Pump	36 MW_{th}	Ø COP 3.5	5.000 MW_{th}
Solar collector	100.000 m²	65%	21 km²
P2H	0 MW_{th}	97%	500 MW_{th}
Gas boiler	4.650 MW_{th}	90%	5.000 MW_{th}
PV	52.000 m²	15%	21 km²
WTG	7.5 MW_{el}	-	16 MW_{el}
EEX transmission	2.000 MW_{el}	-	-
Capacity of heat storage	850 MWh_{th}	-	1500 MWh_{th}
Load power of heat storage	100 MW_{th}	-	500 MW_{th}

Tab. 4: Parameters of the other technologies

3.2. Cost Data:

All used cost data is assumed to be constant during the optimization period of one year. Taxes and levies are not considered and only the costs stated here are used in the model. Also no grid fees or grid connection fees are considered. All units are used to sell and buy on the spot market only. No balancing or reserve power is considered.

Fuel costs

The used gas price is the average value from August 2013 of the EEX traded gas. The Biomass price is assumed to be low because the city of Vienna has long time contracts with the "Österreichische Bundesforste AG" which is shareholder of the biomass CHP Simmering. There are different approaches to determine a price for residual waste. Some set the costs for transportation and treatment as price and some even assume negative prices according to the costs of alternative disposal. In this study the price is assumed to be almost zero but positive. Table 5 shows the used cost data for the fuels.

Fuel costs		
Gas	26.5	€/MWh
Biomass	20	€/MWh
Waste	0.1	€/MWh

Tab. 5: Fuel costs

CO2 costs and emission factors

The used price for CO2 emission certificates is the EEX price from August 2013. Emission factor for Gas is the used standard value whereas biomass is assumed to be emission free and the emission factor for residual waste is very low because the Viennese residual waste consists of up to 50% of residual biomass (Pölz, 2007). Table 6 shows the used CO2 price and emission factors.

emission factors and certificates		
Gas	0.2	t/MWh
Biomass	0	t/MWh
Waste	0.05	t/MWh
Euromix	0.43	t/MWh
CO2 certificate	5	€/t

Tab. 6: Emission factors and CO2 certificates

Investment costs

To calculate the annualized costs of investments a lifetime of 25 years and an interest rate of 5% is assumed for all technologies. The estimated costs for the heat storage are calculated from the cost and technological data of the pressurized heat storage realised in Vienna. The used invest cost data is shown in Table 7.

Investment costs		
PV module	1500	€/kW
Solar colector	600	€/m²
WTG	1100	€/kW
HP	1000	€/kW
P2H	100	€/kW
Boiler	800	€/kW
Capacity HS	24	€/kWh
Load Power HS	200	€/kW

Tab. 7: Investment costs

4. Scenarios and Results

In three different scenarios we calculate the costs and CO2-emissions to cover the yearly heat- and electricity-demand of the modelled region. We observe and compare the technological configuration and the unit commitment of these results to draw conclusions.

4.1. Base scenario:

The base scenario calculates the overall system costs and CO2-emissions to cover the heat and electricity demand by optimal scheduling of the actual installed capacities. According to the demand constraints three demand profiles have to be covered. The electrical demand, the thermal demand within the district heating area and the thermal demand covered by local technologies. We will have a look at the technological shares covering these demands and compare the results.

District heating area:

As stated in section 3 the district heating area covers 36% of the heat demand of Vienna. The base load within this area is covered by the four waste incineration plants (WIP) which are in continuous operation during the whole year. The six cogeneration plants (CHP) cover the mid load and get supported by the five heating plants (DHP) on winter days with high demand. The six cogeneration plants have average operating hours of 4566 hours (see Table 8) with a range from 1461 hours (CHP Simmering 3) to 7443 hours (CHP Donaustadt). The district heating plants are operating 1530 hours on average with a range between 383 hours (FHW Kagran) and 3110 hours (FHW Inzersdorf Süd). Figure 4 shows the share of the different groups of technologies to cover the demand.

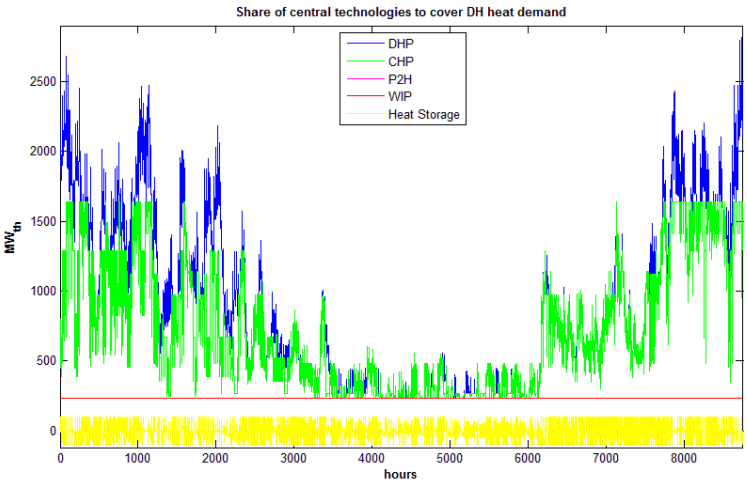

Fig. 4: Share of central technologies to cover the DH heat demand

Not DH area

The area not covered by the district heating system accounts for the remaining 64% of the heat demand of Vienna. As no investments are possible in this scenario the demand is covered mainly by the reference technology gas boiler. The actual installed solar collectors (ST) and heat pumps (HP) do only account for a marginal share of heat supply. Figure 5 visualizes the share of the local technologies.

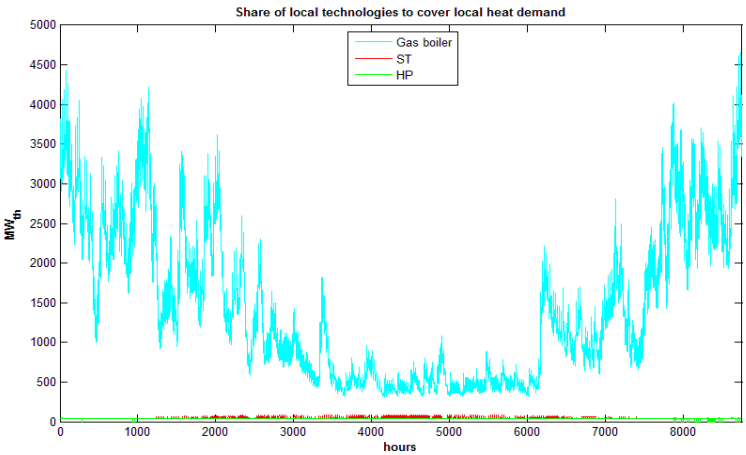

Fig. 5: Share of local technologies to cover the heat demand

Electrical demand:
Due to the possibility of importing and exporting, the electrical load offers the greatest flexibility. Depending on the amount of required heat the produced electricity of the variable CHPs is set according to the actual spot market price. At high prices (approx. over 40 to 45 €/MWh) all of the needed electricity is produced by the CHP's and the overproduction is exported. At low electricity prices (below approx. 40 to 45 €/MWh) only as much electricity is produced as is needed to support the coupled heat demand. The remaining electricity is imported. Figure 6 shows the operation during an average summer month where you can see full operation of the CHPs during the peak-period of weekdays. On weekends or when the electricity price drops below these 40 to 45 €/MWh the CHPs are switched off and the demanded electricity is imported.

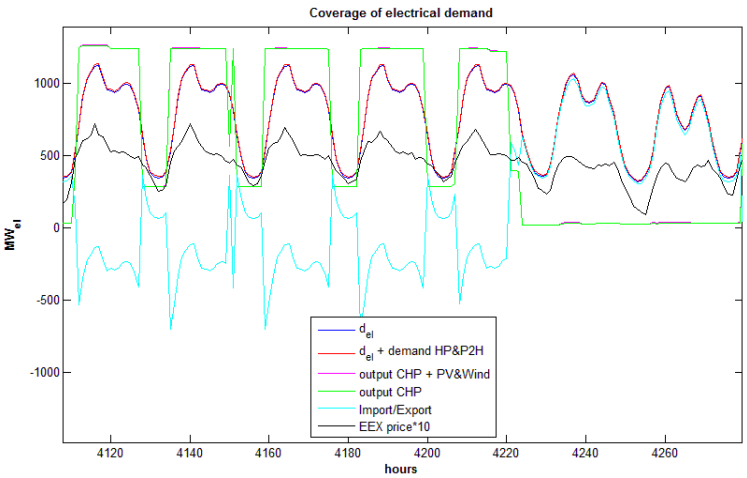

Fig. 6: coverage of the electrical demand

4.2. Optimal system scenario

The "optimal system" scenario shows that investments into additional capacities of the supply structure can lead to cost savings of more than 5% and a simultaneous CO2-reduction of about 9% compared to the base scenario (see Table 9)

District heating area:
Within the district heating area the model invests into an electrical boiler (P2H) of 239 MW. Still the four incineration plants are accounting for the base load but the installation of the P2H leads to less operating hours of both the CHPs and the district heating plants due to heat generation of the P2H unit at electricity prices below approx. 30 €/MWh. The start-ups of the heat plants drops significantly from an average of 31.8 to 17 starts per year (see Table 8) due to the fact that the P2H Unit can be switched on without additional (start-up) costs and the heat can be stored in the heat storage.

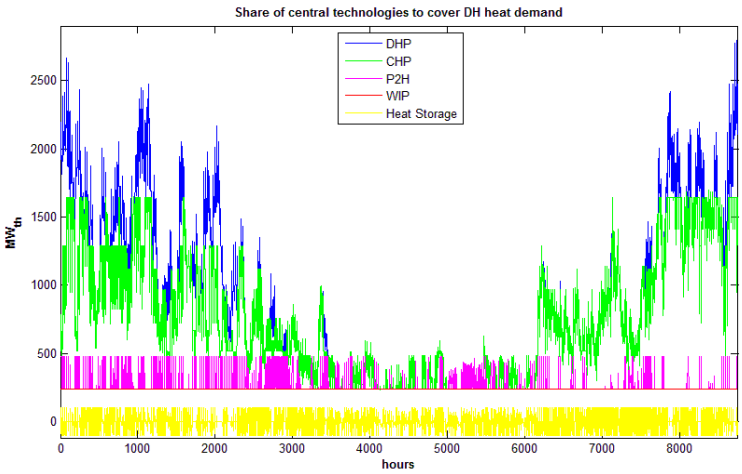

Fig. 7: Share of the central technologies to cover the DH demand

Not DH area:
In the area not covered by the district heating system a big share of over 1 GW of heat pumps is installed to cover the thermal base load. This result would mean that every household should have a heat pump for the base load production and an additional boiler for the peaks. The share of the HP would be even greater

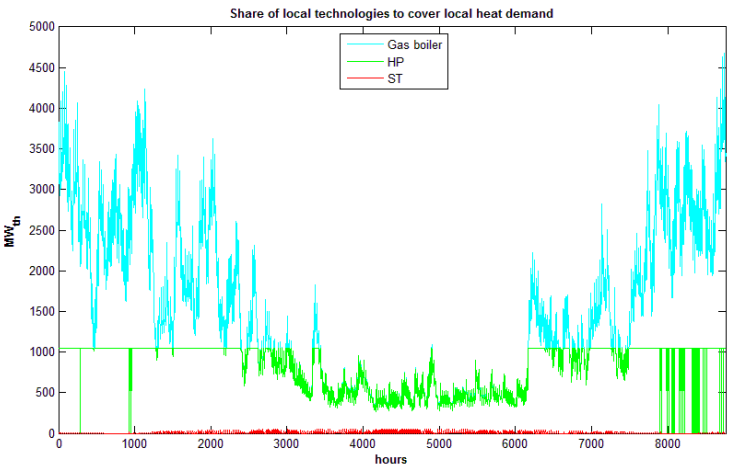

Fig. 8: Share of the technologies to cover the local heat demand

but the gas boilers are already installed and depreciated because they serve as reference technology. However, in reality the HP potential will be lower because of restrictions related to building codes and available space in multi storage buildings. No additional solar collectors get installed and therefore the share of heat generated by solar collectors remains marginal.

Electrical demand:
For cost-effective coverage of the electrical demand, in the optimal system scenario the potential for wind power is exhausted to its maximum of 16 MW. But still the contribution of WTG and PV is very small as can be seen in Figure. 8. The operation mode of the CHP plants is driven by the spot market prices similar to the current state scenario. At spot market prices above approx. 40 to 45 €/MWh the electrical production is maximized and the overproduction is exported. At prices below this threshold the production is reduced or shut down and the needed electricity is imported. Figure 9 compares a typical summer and winter week. The right picture (winter) shows that the electrical demand is elevated due to electrical consumption of the heat pumps. Spikes in demand are caused by switching on the P2H unit at low electricity prices or due to shut down of the HP at high electricity prices.

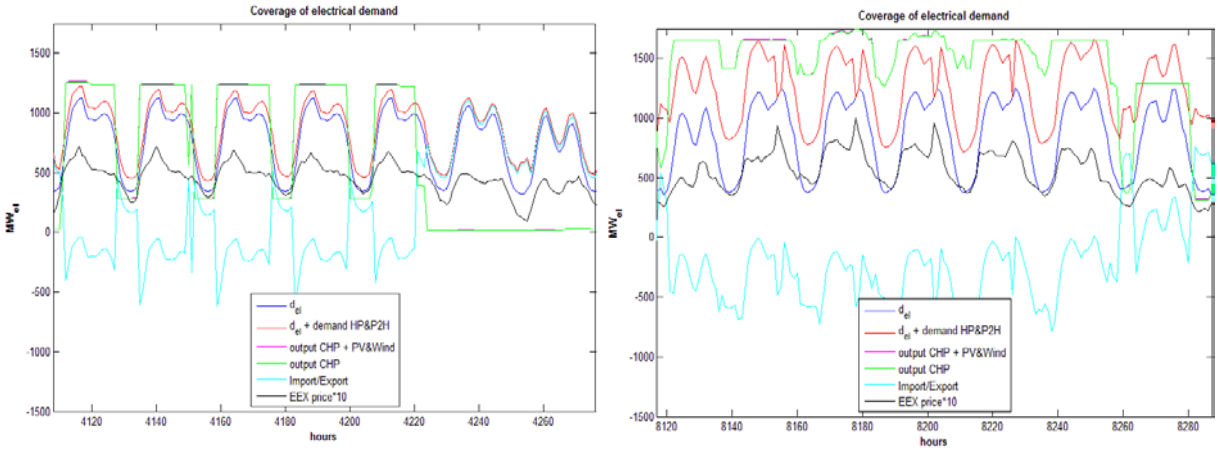

Fig. 9: Comparison of coverage of electrical demand between summer and winter week

4.3. Optimal system with 20% CO2-reduction

The “optimal system with CO2-reduction” scenario calculates the investments and the optimal scheduling of all technologies combined with import/ export of electricity to reach a cost-effective reduction of CO2 emissions by 20% compared to the Base scenario. The results show that with further adaptions in the supply structure, this reduction can be achieved without additional costs compared to the actual structure (see Table 9).

District heating area:
Compared to the optimal system scenario a smaller P2H of only 170 MW is installed within the district heating area. Additionally the load power of the heat storage gets extended so that it can be loaded or unloaded faster. Still the incineration plants do account for the thermal base load. The operating hours of the CHPs do increase while the operating hours of the heat plants drop significantly as can be seen in Table 8. This is because the specific CO2 emission of the heat plants is very high compared to the coupled production in CHPs. Additionally the emissions of the Viennese CHP plants are very low compared to the average emission of the European mix for electricity production due to high efficient gas fired plants. This leads to increased export of electricity.

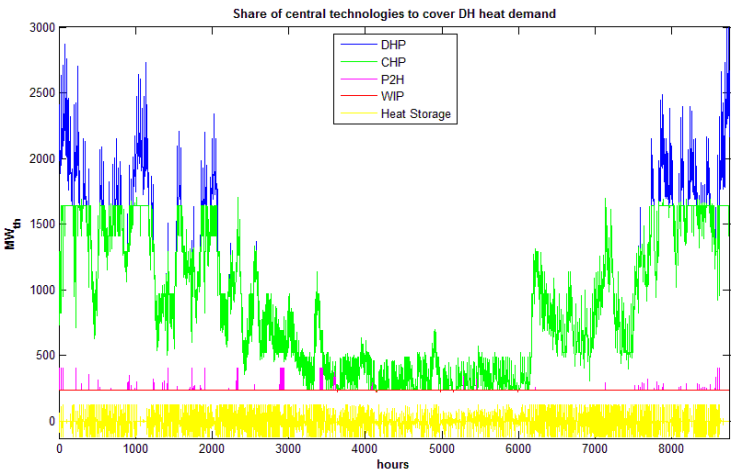

Fig. 10: Share of technologies to cover DH heat demand

Not DH area:
Within the area not covered by the district heating system the share of installed heat pumps is extended to over 1.5 GW. The emission reduction potential due to replacement of gas boilers by heat pump is big because the specific emission of gas boilers to produce heat is high. In this scenario the additional electricity demand for the local heat pumps is met by increased production from CHP plants as can be seen in Figure 12 and Table 8. This means more operation hours and a higher percentage at full-load operation which leads to electricity export instead of import. One reason is that the CO2-emission of each Viennese CHP plant is lower than the average emission of the European electricity generation.

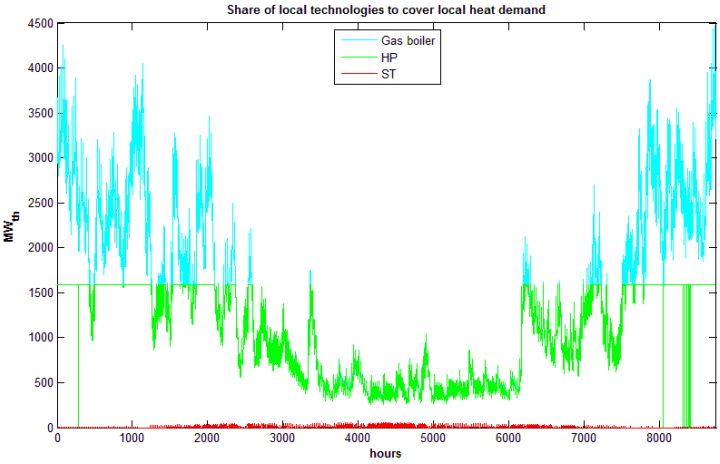

Fig. 11: Share of technologies to cover the local heat demand

Electrical demand:
To reach the required CO2 reduction an expansion of the renewable energy sources wind and PV has to be done to produce carbon-free electricity. As in the optimal system scenario the potential for WTG gets exhausted to its maximum of 16 MW but additionally PV cells of 1.3 Mio m² get installed. In the summer week in Figure 12 the contribution of the PV cells can be seen. Due to the increased electricity demand by running heat pumps in winter the CHPs have more operating hours and full load hours.

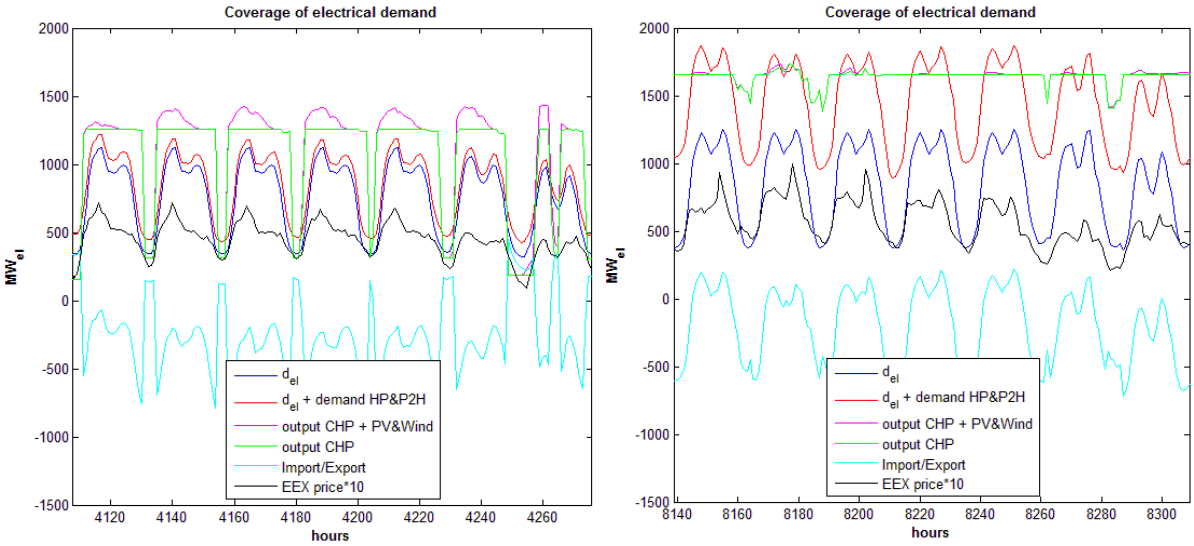

Fig. 12: Comparison of coverage of electrical demand between summer and winter week

Table 8 shows a comparison of the operating hours of the different technologies whereas Table 9 shows a detailed breakdown of the different production and investment costs for the different technologies.

	Base Scenario			Optimal System			20% CO2-Reduction		
	Operating hours	full load hours	Sart-ups	Operating hours	full load hours	Sart-ups	Operating hours	full load hours	Sart-ups
WIP	8760	8760	0	8760	8760	0	8760	8759	0
CHP	4566	4112	27.8	4429	3936	27.3	5838	5541	17.3
DHP	1529	879	31.8	1297	745	17.0	778	421	16.8

Tab. 8: Operating hours of the different technology types

€	Base scenario	Optimal System	20 % CO2-Reduction
Total system Costs	**804.768.000**	**762.985.000**	**799.460.000**
Start-up costs (WIP, CHP & DHP)	**3.293.800**	**3.319.500**	**1.830.500**
Production costs central technologies	**458.119.700**	**453.281.600**	**614.813.200**
WIP	1.062.700	1.062.700	1.062.600
CHP	418.970.000	415.170.000	595.190.000
DHP	38.087.000	31.832.000	18.229.000
P2H (electricity costs)	-	5.216.900	331.600
Production costs local technologies	**379.262.000**	**218.090.000**	**153.060.000**
Gas boiler	377.010.000	165.580.000	85.694.000
Heat Pump (electricity costs)	2.252.000	52.510.000	67.366.000
Total Investment costs	**0**	**74.318.000**	**133.741.200**
HP	-	71.959.000	110.230.000
P2H	-	1.695.600	1.214.800
WTG	-	663.400	663.400
PV	-	-	21.320.000
Load power of heat storage	-	-	313.000
EEX trading balance	**-33.661.000**	**71.700.000**	**-36.290.000**

Tab. 9: Break-down of the costs

5. Discussion of results and conclusions

The model results show that the most efficient reduction in total costs and also CO2-emissions can be achieved by reducing the share of the decentralized technology of gas boilers by heat pumps. The result indicates that households should install heat pumps for the base load production and use the already installed gas boiler as peak-load unit. Although the implemented technology is an air-source heat pump with significant potential even in cities, the combination with a gas boiler will not occur in a relevant share of households due to higher investment costs. The problem here is that investment decisions of single households do not accord to efficient decisions for the overall system.

The emission reduction potential within the district heating system seems to be limited because this technology is already efficient due to a high share of cogenerated heat. The only potential here is given by reduced operation of the gas fired district heating plants. This means that it is recommendable to develop district heating systems in areas where it is economically feasible whereas economic feasibility is easier to reach in areas where waste heat is available. The problem here is to define parameters and regions where a district heating system would have economic benefits. Also because in many households there are already other types of technology installed and the willingness to change the heat supply system may be low.

A solution would be to use comprehensive infrastructure planning for whole regions considering existing technologies and potentials of different supply structures. Based on this planning, political subsidies for efficient decentralized technologies or areas with connection obligations to district heating could be developed.

The prices were set to the values listed in section 3.2 and were not varied for the three different scenarios because the aim of this research was to identify the potential for a given structure. Especially energy carrier prices, investment costs and electricity prices vary significantly from year to year and therefore it would be recommendable to vary them or use values from different years to evaluate sensitivities of the results.

The installation of the P2H unit may be overrated in this model because grid connection fees are not considered here. According to the actual law situation P2H units have to pay annual grid fees doubling their annual costs compared to only considering annualized investment costs. This may also be the reason why the P2H unit in this model is switched on at electricity prices as high as 30 €/MWh.

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