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Sector Coupling Potential of a District Heating Network by Consideration of Residual Load and CO_2 Emissions

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Abstract: The growing share of fluctuating renewable electricity production within the German energy system causes the increasing necessity for flexible consumers, producers, and storage technologies to balance supply and demand. District heating networks with combined heat and power units, Power-to-Heat applications, and thermal energy storage capacities can serve as one of these flexible options. In this context, a simulation model of the district heating network of the rural community *Dollnstein*, *Germany*, was built. With the residual load of different regional areas (*Germany*, *Bavaria*, *Eichstätt*, *Dollnstein*) it is investigated, how the heat generators can operate in an electricity market beneficial way. Two different control algorithms were evaluated: Due to a correlation between the residual loads and the CO_2 emissions of the electricity mix, the CO_2 savings achieved by this control algorithm are determined. Another way to operate electricity market beneficial is to consider the current CO_2 emissions of each region. The main outcomes of this paper are, that there is a high potential for sector coupling by shifting the operation times of a CHP and a heat pump according to the residual load. The electricity demand of the heat pump can be met in terms of low CO_2 emissions of the electricity mix, while the CHP can replace electricity with high CO_2 emissions. These results can be improved, by considering not the residual load but the current CO_2 emissions in the control algorithm.

Keywords: district heating networks; sector coupling; residual load; CO_2 emissions

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1. Motivation and Objectives

The European power generation capacities and respectively the share of renewable energies (RE) with a fluctuating generation profile such as wind and photovoltaic (PV) power plants are steadily increasing [1]. In Europe in 2019, the share of electricity from RE amounts to 30%, which presents an increase of 70% since 2009 [2]. The situation in *Germany* with a share of RE of 42% is comparable [3]. This increase in RE leads to higher fluctuation in the power grid, resulting in periods where electricity supply by renewable sources exceeds the current demand.

One option to counteract these periods is the demand side management of electricity-based heat generation units such as heat pumps (HPs) combined with thermal storages. Another countermeasure is the utilization of a combined heat and power plant (CHP) for electricity supply during periods of low energy supply by RE. Operating the aforementioned units in a grid-supportive manner can also be beneficial for the heat generation of these systems, with regard to both their CO_2 impact and an economically viable operation. The CO_2 emissions of the German electricity mix vary depending on the current share of RE. The amount of CO_2 emissions that can be attributed to the German electricity mix changes according to the amount of fossil energy required to meet the electricity demand. Consequently, HPs can be operated and supplied with electricity at low CO_2 emissions. This leads to a low carbon footprint of heat generation by HPs. Additionally, if the price of electricity will map these fluctuations in near future, the HP operator could benefit from frequent low electricity prices. In contrast, CHPs can supply energy at times with higher CO_2 emissions in the power grid, which could lead to higher revenues for the operator.

This is a chance to combine the heating sector with the electricity sector and to reduce CO_2 emissions within the heating sector, especially for district heating networks (DHNs). In 2019, the renewable heat generation for German DHNs—including waste heat recovery and waste heat from biogenic and non-biogenic waste amounts to 30% and provides a high potential for improvement [4]. The flexibility of conventional thermal power plants is limited by minimal load constraints and maximum load change ramps. These constraints depend on power plant type and design. Additionally, typical cogeneration plants for district heating grids are operated as baseload generation, the control is based on the heat demand of the heating grid. Without additional control strategies, these cogeneration plants may also produce during high output of RE.

To counteract the fluctuation of electricity supply of RE, current scientific literature reveals a variety of potential solutions. In this context, the term *Smart Grid* is used to describe the adaption of flexible electricity consumers as well as operating power plants, e.g., CHPs or battery storages, to counteract the fluctuation of RE [5]. However, the focus is mainly on the electricity sector. In order to meet the challenges, *Smart Energy Systems* in future must include all energy sectors [6].

In some articles, CHP and HPs are already considered as part of electricity system. Combined with thermal storages, these units can be operated in a flexible and grid-supportive manner and therefore combine the heating and electricity sector. Depending on the need of the consumers, CHPs are operated as heat-controlled or electricity-controlled units. From a technical point of view, it is possible to operate the CHP in a grid-supportive manner to compensate for the fluctuations of the RE [7–10]. Magni, Quolin and Arteconi [11] assessed the potential contribution of DHNs equipped with CHPs and HPs (in combination with heat storage options) to the flexibility of the future Italian power system, indicating a high potential of such DHNs if widely applied. A similar statement is made by Schwaeppe et al. [12], who analyzed the intersectoral benefits of DHNs within the context of the German energy system. Although DHNs will not reduce the demand for high-voltage, direct current (HVDC) transmission lines, the authors consider DHNs capable of providing short-term flexibility. De Lorenzi et al. [13] investigate a DHN supplied by a CHP unit to cover the heat demand of two schools and sport hall. Within certain time windows, the generated electricity can be sold to the power grid. The generated heat is stored within a thermal storage. By utilizing an algorithm based on model predictive control, the authors report that—depending on different assumptions regarding the prediction horizon—the DHN operator can (partly) fulfill both the demand from the power grid while still maintaining the end users' indoor comfort.

Since the compressor of the HP is driven by electricity, the operating time could also be adjusted to the yields of RE. Dar et al. [14] describe a net-zero energy building with PV-collectors and an air-water HP. By adapting the control strategy and combining a thermal storage, the peak loads during energy exchange with the power grid can be shifted and the demand during peak loads can be reduced by 30%. This reduction can be improved by integrating a battery storage [15].

However, the aforementioned references show solutions and integrations of single plants in the power grid. DHNs can combine several of these or larger plants in one grid and thus represent greater load shifting potential. Similar to a *Smart Grid*, also a *Smart Thermal Grid* can be generated to integrate more RE for covering the heat demand [6,16]. In order to consider all energy sectors, it is necessary to combine these grids into a *Smart Energy System* [6]. Streckienė et al. [17] show that it is feasible to operate a CHP of a DHN considering the German spot market. However, the economic efficiency depends on the size of the CHP unit and the thermal storage, as well as prices for natural gas, electricity, and national policy regulations. In addition to that, the results of Sorknæs et al. [18], who were simulating a DHN in Denmark, show 25% increase of operating hours of a CHP unit with simultaneous reduction of the heat production costs due to a grid-supportive operation of the CHP (see Figure 1).

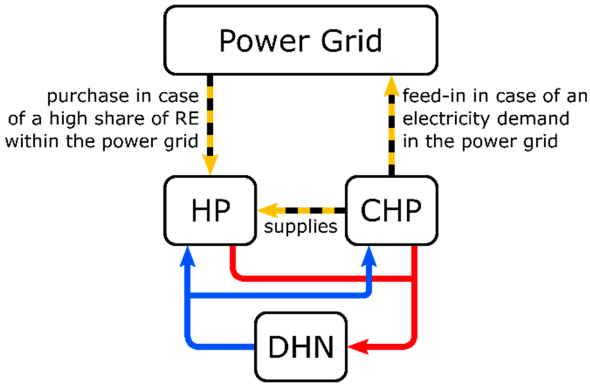

Figure 1. Connection of a HP and a CHP operating in a DHN to the public power grid. - = Low temperature heat; - = High temperature heat; - = Electricity.

This study on the other hand focuses on how small DHNs can be operated in a way that serves the power grid and the electricity market, while at the same time reducing CO_2 emissions. As the size of heat generators within small DHN is too small to participate on the regulatory electricity market and provide balancing power for the grid, the focus of this study is on operation modes that serve the electricity market and reduce CO_2 emissions of the current electricity mix.

In Section 2, the boundary conditions are explained. It will be shown how the residual loads and CO_2 emissions for the German power grid are calculated. Since the grid cannot always be assumed to be ideal, the balancing effect for smaller regions is studied as well. We reduced the framework of a local DHN from country (*Germany*) via state (*Bavaria*) down to region (*Eichstätt*) and district (*Dollnstein*). As the data were not available for these entities, it is also shown how we created data for this cellular approach. In Section 3, the DHN and its representation in a simulation model is introduced and in Section 4 the implementation of the two control strategies in the simulation is shown. In Section 5, the results of the simulations are shown and summarized in Section 6.

2. Residual Loads and CO_2 Emissions of the German Power Grid

2.1. Residual Load

Residual load refers to the difference in energy demand and the electricity generated by RE. If the power generation by RE is higher than the current demand, this is called negative residual load. On the other hand, if the energy demand is higher than the energy supply by RE, this is referred to as a positive residual load. Currently, there are few negative load peaks across Germany. In 2020, this corresponded to 2.3 TWh of surplus electricity. However, it is expected that these peaks of the residual load will increase significantly as the expansion of PV and wind power plants continues. In 2030, a surplus of 34.5 TWh_{el} is forecasted. Due to the numerous wind energy plants, mainly northern Germany has been affected by electricity surpluses so far. [19]

As the following simulation study of the DHN in *Dollnstein (Germany)*, which is used as a case study, is based on measurement data for 2018, the German residual load of 2018 is considered (see Figure 2). Figure 2 shows high fluctuations especially in the winter period from November until March, caused by unsteady availability of wind energy. Another seasonal impact on the residual load can be seen due to high yields of installed PV systems in the summer period. This leads to fundamentally lower residual loads. Furthermore, it is apparent that there are weekly fluctuations, caused by a lower energy demand on weekends. In contrast to 2020, there are no negative residual loads in 2018.

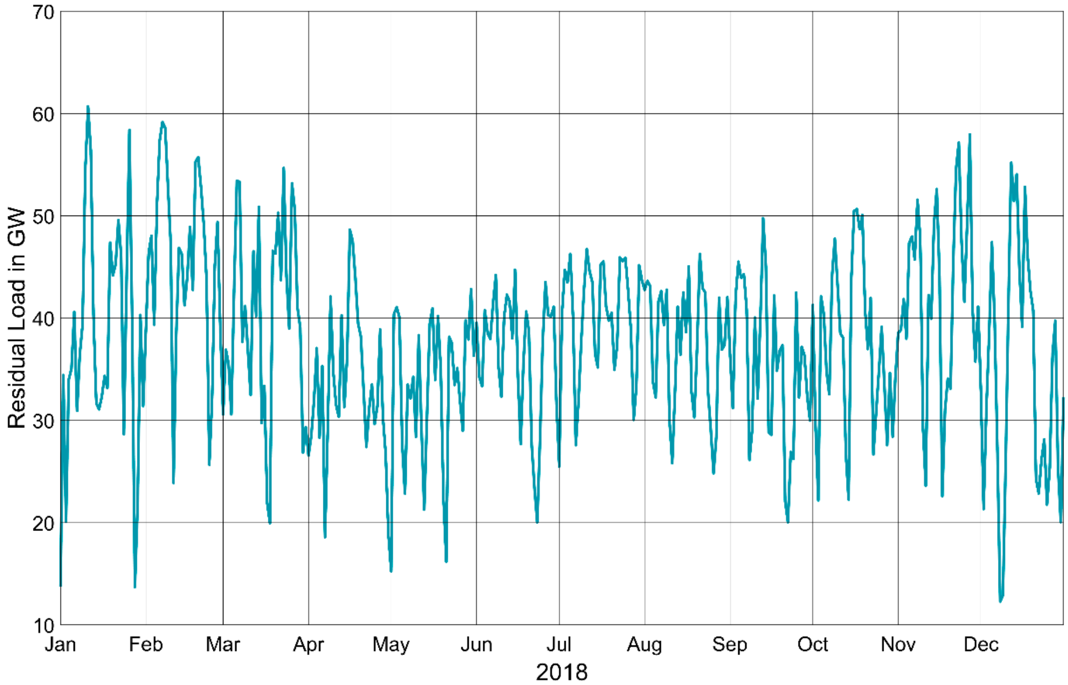

Figure 2. Residual load of Germany in 2018 based on the data of *Agora Energiewende* [20].

The data source used is the *Agorameter* published by *Agora Energiewende [20]*, which uses data directly from the *European association for the cooperation of transmission system operators for electricity (ENTSO-E)* and the *European Energy Exchange (EEX)* stated in *Leipzig (Germany)*. The following power plants are used to determine the generation curve of inflexible REs such as:

- hydropower,
- photovoltaics,
- wind onshore,
- wind-offshore and
- other RE (geothermal, landfill, sewage, and mine gas).

All conventional (e.g. coal-fired or nuclear) as well as pumped-storage plants, which are highly regulated as storage facilities, are omitted from the calculation. In addition to that, electricity generated by biomass is excluded, since its operation is already regulated in a cost-optimized manner by the operator, which results in a low accessible potential.

The aforementioned grid restrictions and the increasing importance of a decentralized view of the electricity supply is required to handle fluctuations within the power grid. A possibility to improve the grid-supportive operation of decentralized energy consumers and suppliers can be the so-called *cellular approach*, also named a *microgrid* [21]. The German power grid is divided into four regulation zones, which are controlled by four different transmission system operators. In order to integrate RE more efficiently, which also means considering regional circumstances, further dividing the regulation zones into smaller zones can be beneficial. These different regional cells operate more autonomously but can communicate with neighboring cells if there is an electricity exchange needed.

Unfortunately, for the calculation of residual loads for smaller units such as *Bavaria* or the municipality of *Dollnstein*, the authors of this work are not aware of any data of a similar quality to the German data that can be used. Consequently, local residual loads had to be generated.

First, various sources were consulted for data on electricity supply and demand, before local residual loads were determined based on geographical units. This can be seen critically, since no network topology and restrictions are considered, which would be mandatory in case of a detailed power system analysis. Since data from transmission grid operators, e.g., for the transmission grid (*Tennet*) and the distribution grid responsible for *Dollnstein* (*Main-Donau-Netz*), are freely available, the areas *Bavaria*, *Eichstätt*, and *Dollnstein* are considered as ideal cells in which there are no grid restrictions, which means that electricity can be ideally and always distributed [22,23]. This approach is also called the cellular network.

The generation load curves of RE result from normalized data of existing plants of *Naturstrom AG*. PV, wind energy plants, and one hydroelectric power plant were analyzed. Since exact forecasts of electricity generation from PV and wind power plants are difficult to realize, data measured in *Bavaria* in 2017 serve as the basis for the evaluation. To compensate for site-specific parameters, the curves are normalized to highly simplified values. Since a detailed adjustment to a reference site would be too far-reaching, these inaccuracies must be considered in the result. The normalized load curves are then scaled to different grid areas and regions based on the installed plant capacity or the annually generated energy. Thus, generation load curves in 15 min resolution are generated for the observation areas *Bavaria*, *Eichstätt*, and *Dollnstein* and can be used to determine the respective residual load curves. A detailed overview of the methodology is shown in Figure 3.

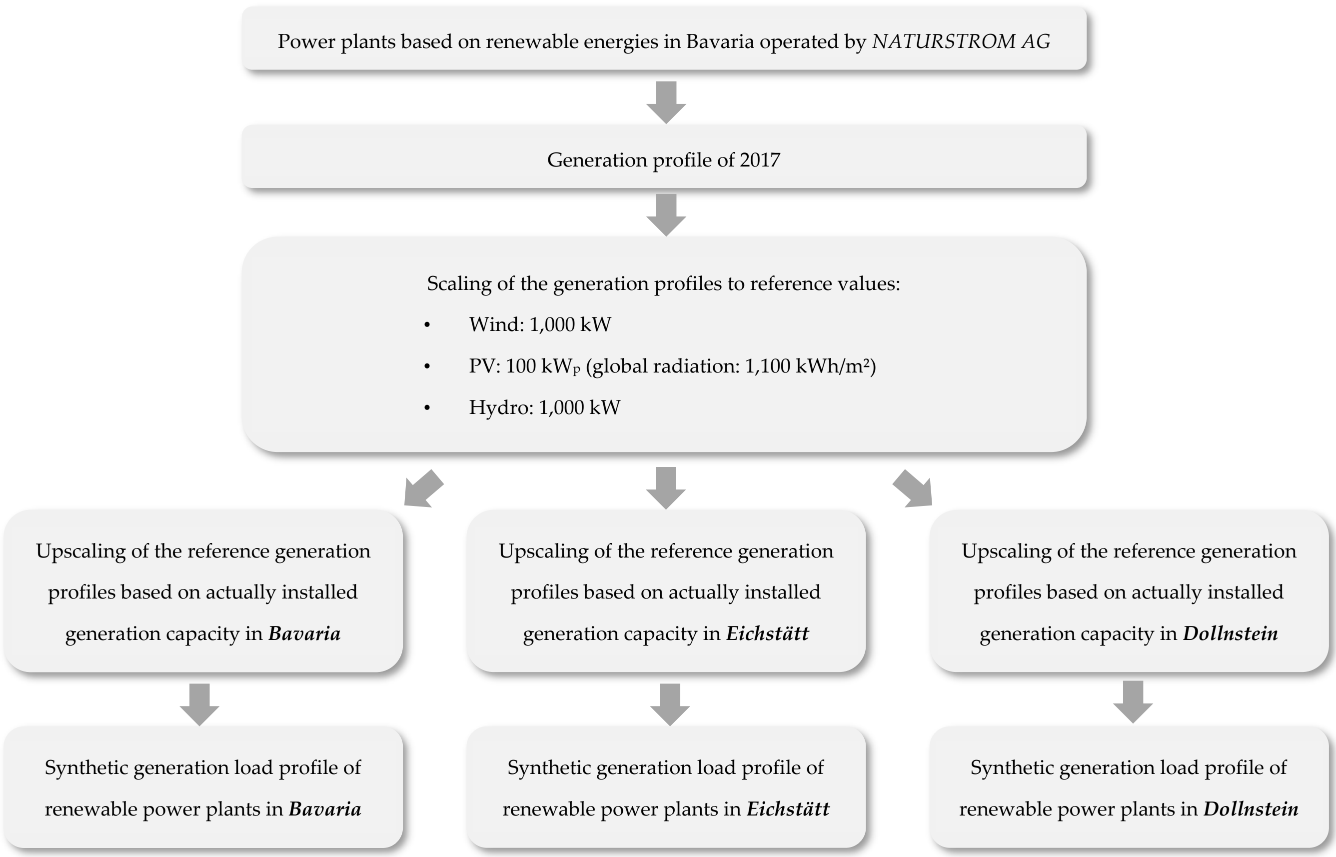

Figure 3. Methodology to develop synthetic generation profiles of renewable power plants based on measurement data of *Naturstrom AG*.

In contrast to the generation profiles, standard load profiles (SLPs) are used to model the electricity demand in the chosen observation areas—according to the *German Association of Energy and Water Industries (BDEW)*. These SLPs depend on categorization, weekday, type day, and public holidays and thus offer the possibility to generate load profiles for different years or federal states. The load profiles for *Bavaria* of 2018 are derived from *EnergieNetz Mitte GmbH* [24]. Furthermore, two necessary simplifying assumptions are made. For example, only conventional consumers without time-shifting loads are considered and the consumer structure is determined in a very simplified way based on the consumption data of all private households and industries. The SLP *H0* is assigned to the load of private households. The remaining electricity demand, which is determined by the difference between total electricity demand and the demand of private households, is assigned to the SLP *G0-general industry* [25].

By means of this preliminary work, the regional residual load curves for 2018 respectively 2017 could be determined. The residual load of *Bavaria*, *Eichstätt*, and *Dollnstein* is based both on values of 2017 and 2018. As mentioned above, the electricity supply results from available data from 2017, whereas the electricity demand is based on data from 2018. However, due to comparable weather conditions in the first quarter of the year, these differences can be neglected for this investigation. The occurrence of negative residual loads is low for all areas. For *Dollnstein* and *Bavaria*, the times of negative residual loads are usually in summer, which corresponds to the dominance of PVs, as is to be expected for *Bavaria*. *Dollnstein's* residual load profile is particularly dependent on the season since the relative share of demand of private households is particularly high. In the district of *Eichstätt*, on the other hand, the negative residual loads increasingly occur in winter, since there is a higher share of wind energy. To compare the residual load curves of the different regional levels, six days from 17th until 22nd February were selected and the curves were shown comparatively (c.f. Figure 4).

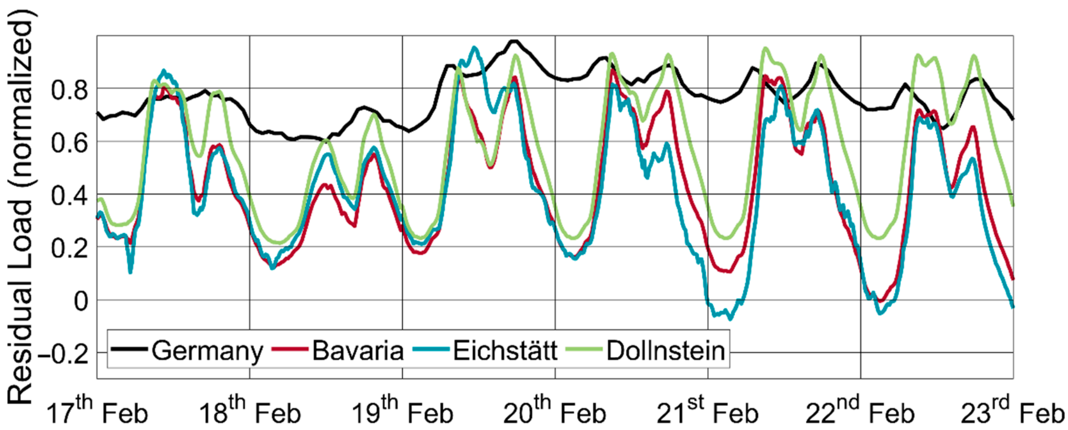

Figure 4. Comparison of the normalized residual load curves in *Germany*, and the German regions *Bavaria*, *Eichstätt*, and *Dollnstein* from 17th February until 22nd February.

A normalization of the residual loads of the aforementioned areas allows for their comparison. According to Figure 4, the residual load of Germany is higher in comparison to the regional levels of observation and is also subject to significantly fewer fluctuations. Interregional fluctuations can be well balanced throughout Germany. However, such a compensation is more difficult to implement across *Bavaria* or within the *Dollnstein* market due to mostly identical weather conditions.

2.2. CO_2 Emissions

The price of European electricity is determined at different electricity exchanges. As a subsidiary of the *EEX*, the *EPEX SPOT SE* stated in Paris, France, takes over the spot market for France, Germany, Switzerland, and Austria which includes the Day-ahead and the Intraday trading. The electricity price at the wholesale depends on the so-called *Merit Order*. The costs of a power plant are composed of variable and fixed costs. During operation, at least the variable costs have to be covered to enable short-term economical operation. Therefore, in that case, the variable costs can be referred to as the marginal costs. Within the available generation capacity, the power plants are arranged according to their specific marginal costs, what is called the *Merit Order* (c.f. Figure 5). Afterwards, the electricity price is determined by the most expensive power plant, which is required to meet the demand according to the *Merit Order*.

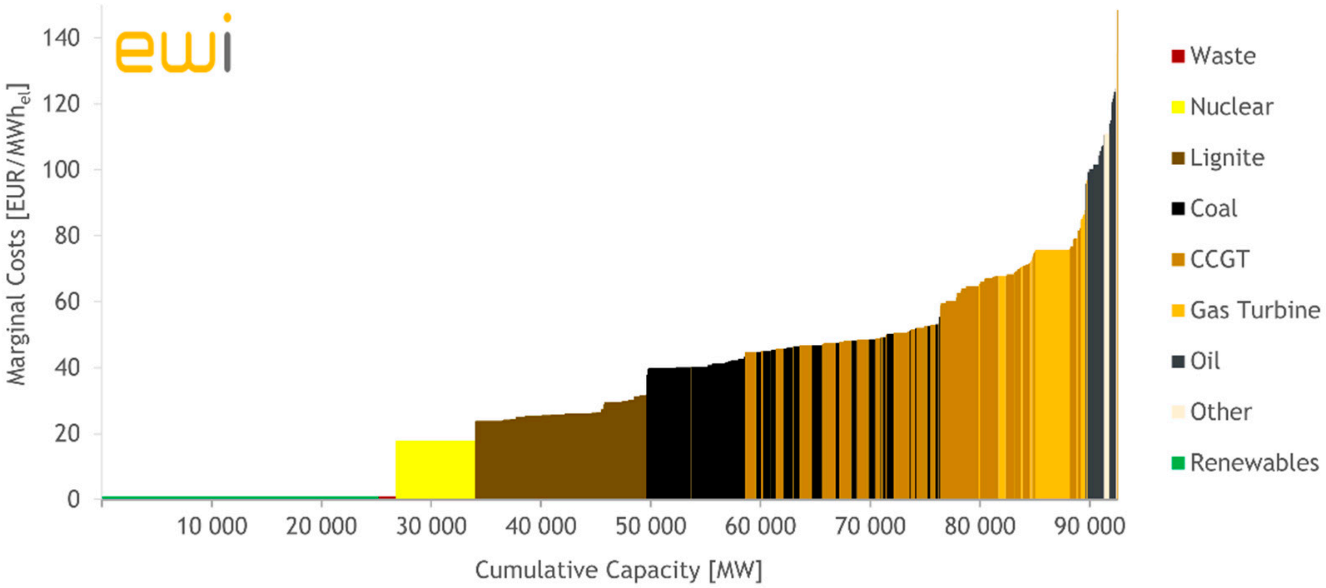

Figure 5. *Merit Order* of power generation in Germany in 2018 [26].

Due to an increase in the electricity supply of RE, the *Merit Order* of the fossil power plants has shifted to the right. As a result, the maximum value of the marginal costs for being allowed to feed into the power grid, are reduced. RE systems have almost no marginal costs, as they do not have to invest in fuel or CO_2 certificates. This is the reason why it is hardly possible to operate fossil power plants economically, especially during periods with a high share of electricity supplied by RE. In addition to that, it is likely to displace fossil power plants with a power plant with lower marginal costs and usually less CO_2 emissions. If there is a low share of RE and therefore the limit of the marginal costs is higher, there is a better chance to be considered within the *Merit Order*. Table 1 shows an overview of the specific CO_2 emissions of each fuel, which are needed to determine the specific CO_2 emission curves for the electricity mix for *Germany*, *Bavaria*, *Eichstätt*, and *Dollnstein*. As only production is considered and no LCA analysis is made RE electricity production is considered with 0 g/kg.

Table 1. Specific CO_2 emission for electricity generation for fossil fuels in g/kWh [27,28].

Fossil Fuel for Electricity Generation	Specific CO_2 Emissions in g/kWh
Lignite	1090
Hard Coal	820
Natural Gas	370

With the hourly values of the power generation in Germany [27] and the values in Table 1, hourly specific CO_2 emissions can be defined.

The calculation for the Bavarian CO_2 impact of the electricity mix differs considering RE in the Bavarian electricity mix. If the demand is higher than the supply by RE, the remaining demand has to be met by an imported electricity mix. Therefore, for the imported electricity mix for *Bavaria* is assumed to be the German electricity mix excluding the Bavarian power generation. In addition to that, the fossil-fuel power generation of *Bavaria* has to be considered as well. This means, the imported electricity mix contains the German electricity mix without RE generated power of *Bavaria*, as it is already considered in the *Bavarian* residual load. As a result, the CO_2 emission curve of *Bavaria* consists of the CO_2 emissions of the German electricity mix and the emissions of the Bavarian fossil-fuel power generation.

In the case of *Eichstätt* and *Dollnstein*, the CO_2 impact of the entire German electricity mix is used, including the electricity supplied by RE, as the double consideration of the regional RE can be neglected.

Figure 6 illustrates the normalized CO_2 emission curves for *Germany*, *Bavaria*, *Eichstätt*, and *Dollnstein* between February 17th until 22nd of 2018. The characteristics of these values are similar to those of the residual loads. While the German CO_2 emissions (black) are quite steady, the *Bavarian* (red) and especially *Eichstätt's* (blue) values show high fluctuations. The low CO_2 emissions at nighttime between February 21st to 23rd result from a high share of wind energy in *Bavaria* and *Eichstätt*. The CO_2 emissions of *Dollnstein* (green) do not vary as much, as there was no wind power plant within this area in 2018. Additionally, the electricity supply by PV systems leads to low emission values in the afternoon for *Bavaria*, *Eichstätt* and *Dollnstein*. In *Dollnstein*, fluctuations by RE can only be caused by the yields of photovoltaic systems.

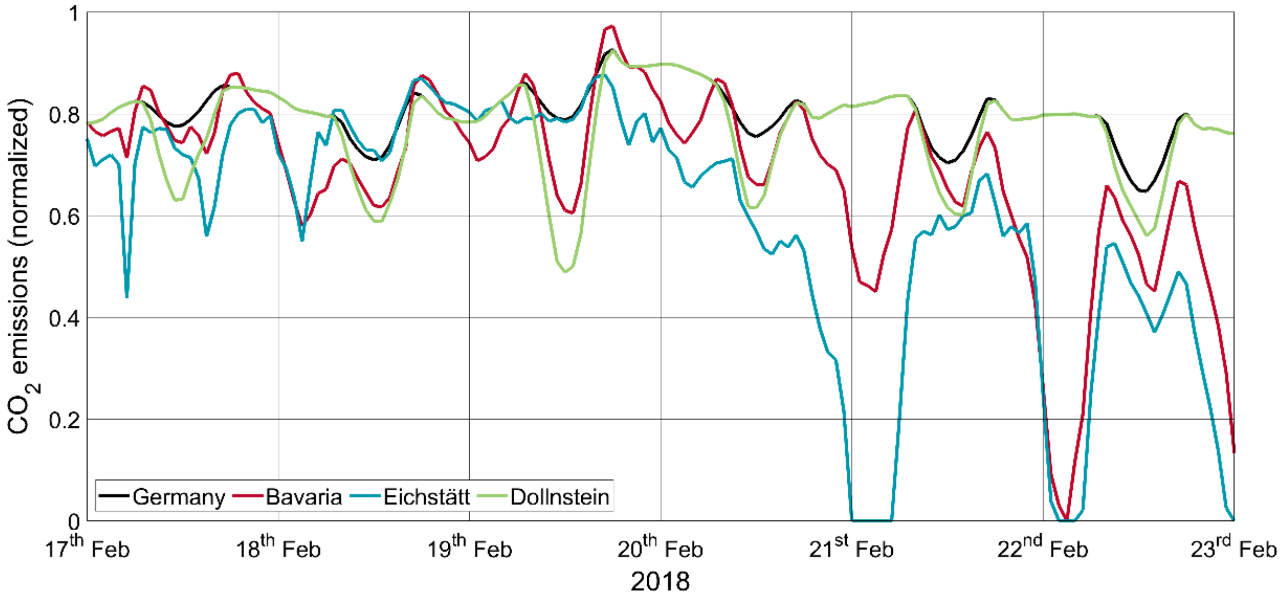

Figure 6. Comparison of the normalized CO_2 emission curves in *Germany*, and the German regions *Bavaria*, *Eichstätt*, and *Dollnstein* from 17th February until 22nd February.

2.3. Correlation between Residual Load and CO_2 Emissions

Concerning Section 2.1, the energy supply by RE is crucial for determining the residual load. Therefore, the values of the CO_2 emissions of the German as well as regional electricity mix show a correlation to the (regional) residual load (c.f. Figure 7). Especially between 21st and 22nd of February, the graph of *Eichstätt* and *Bavaria* shows a low respectively negative residual load due to a high share of RE and specific CO_2 emissions of 0.0 g/kWh. However, there are times when the two curves differ at specific time steps.

For example, the residual load of *Eichstätt* mostly depends on wind energy. During the nights on February 19th and 20th the residual load of *Eichstätt* is low, whereas the CO_2 emissions of the electricity mix remain high at the same time. This means, the CO_2 emissions indicate a low share of RE, i.e, there was less wind energy available. Simultaneously, the residual load is low, which shows a low electricity demand during these periods. To conclude, both the residual load as well as the CO_2 emissions depend on the electricity supply by RE, which leads to a frequent correlation between the two curves. Since the residual load also includes the electricity demand, there are time periods, when the two curves differ.

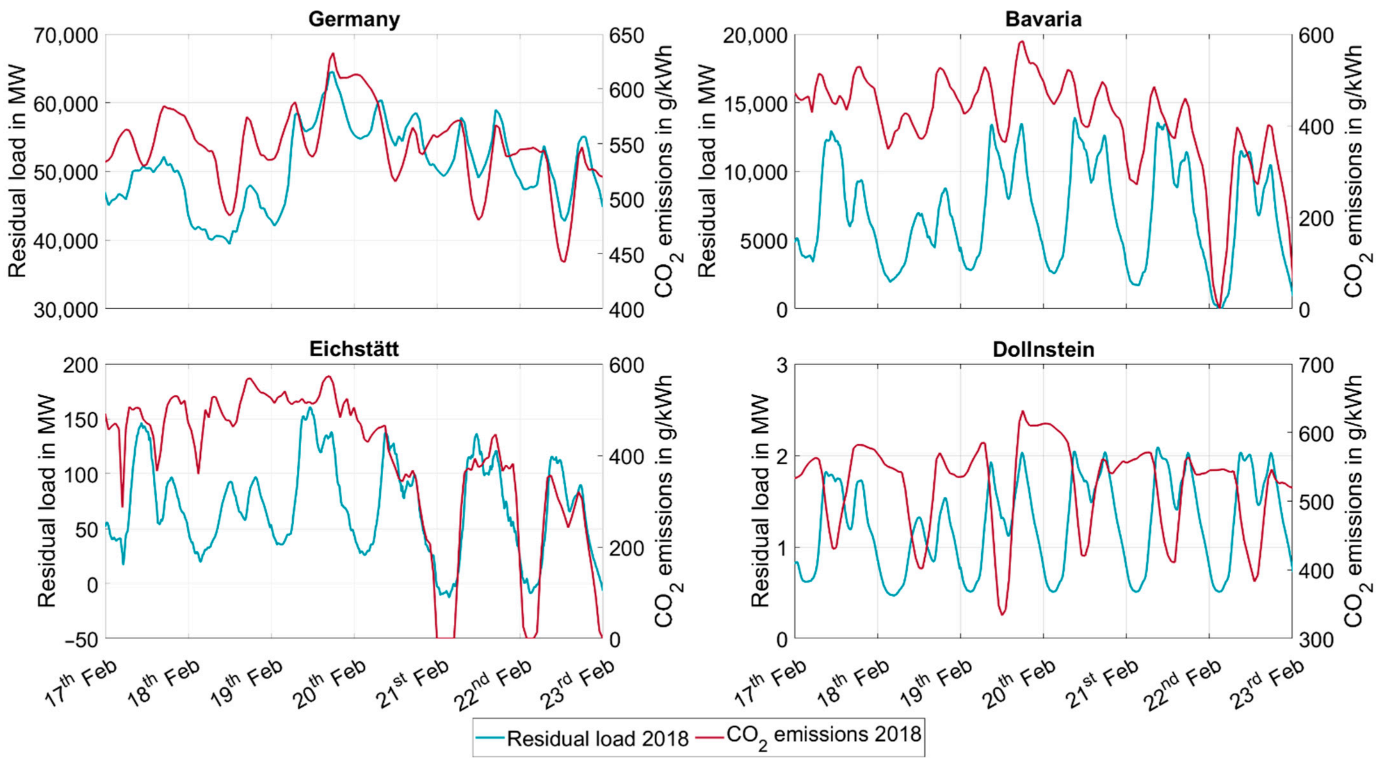

Figure 7. Comparison of the behavior of the residual load curves and the CO2 emissions of the electricity mix in each region for *Germany*, *Bavaria*, *Eichstätt*, and *Dollnstein* from the 17th of February until the 22nd of February 2018.

3. The DHN of *Dollnstein* and Its Modelling

In order to study a grid-supportive control algorithm in a DHN, a small network in *Dollnstein* (*Germany*) is used as the object of investigation, which was constructed in 2014. As of today, there are 21 consumers connected to this DHN with an annual heat demand of 1.24 GWh in 2020. During the winter period from November until April, the heat demand is covered by a central CO_2-HP, a Liquefied Petroleum Gas (LPG)-fired CHP, a peak-load-boiler, and a solar thermal system within the central district heating station (c.f. Figure 8). During that time, the DHN serves as a classical DHN with flow temperatures of about 75 °C. By implementing both a high-and a low-temperature storage at the central district heating station, the efficiency of the heat generation systems is improved. During the German summer period (May–October), the reduced heat demand (solely hot water) provides the possibility to reach flow temperatures of the DHN of approximately 45 °C. Mostly, the heat is only supplied by the solar thermal system. To comply with the hygiene requirements for domestic hot water, decentralized HPs serve as a temperature booster. This control strategy (c.f. Table 2) aims to minimize the thermal losses of the DHN. Further information about the operation and results of the measurement evaluation can be found in [29].

A particular potential for sector-coupling is served by the combination of the central HP and the CHP in a common central district heating station. The generated electricity from the CHP supplies the whole DHN with electrical energy. To ensure a high level of self-consumption, the central HP and the CHP unit are operated as simultaneously as possible. The electricity generated by the CHP unit can thus be used directly to drive the compressors of the HP. In 2019, the electricity demand of the HP was 59.8 MWh. After adapting the operating times of the CHP and the central HP, a share of only 16.4% of the electricity is imported from the public power grid. Particularly during the winter months, the electricity drawn from the public power grid can be reduced in this operating mode. The parallel operation mode of the two heat generators enables an external electricity purchase of only 3.3% during the winter operation mode 2019. The CHP unit has a nominal electrical output of 160 kW_{el}, intended to supply the central HP with an electrical power of 140 kW_{el} and some other components of the DHN. However, due to various maintenance activities, a maximum of two out of three compressors were running. Since March 2018, the HP has been operating with only one compressor and thus with an electrical power consumption of approx. 44 kW_{el}. As a result, the CHP unit must either run at reduced power or feed more electrical energy into the public power grid during full-load operation.

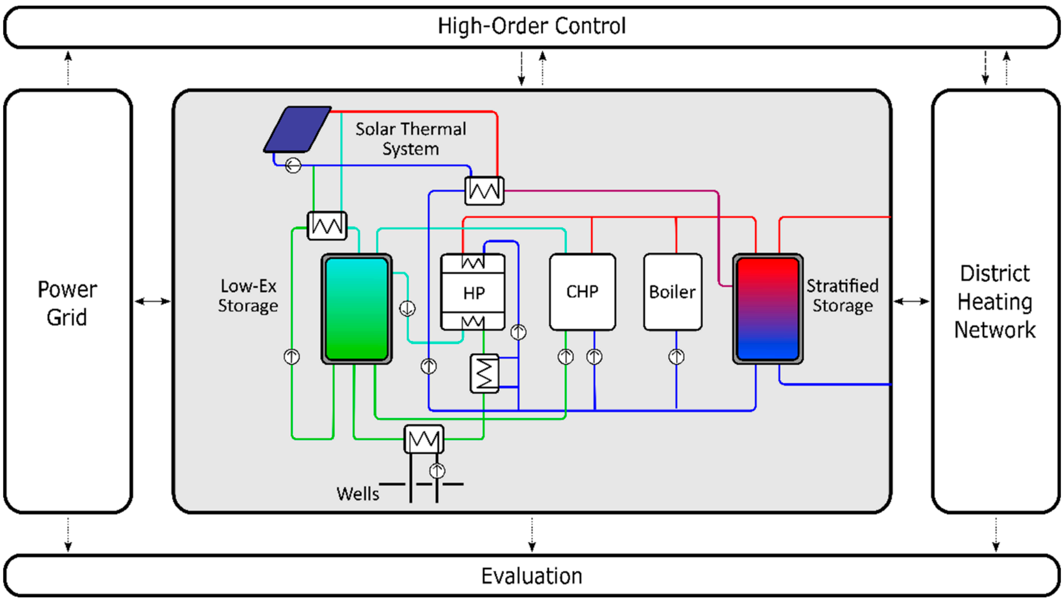

Figure 8. Structure of the simulation model of the DHN in *Dollnstein* [29]. Solid arrows represent the exchange of physical quantities (i.e., heat and electricity), dotted arrows indicate an exchange of information (e.g., measurement data), dashed arrows represent control signals.

Table 2. Control strategies and corresponding flow and return temperatures of the DHN in *Dollnstein* during German winter and summer period.

	Mode of DHN Units		**Flow Temperature DHN**	**Return Temperature DHN**
Winter period (Nov–Apr)	CHP:	on	~75 °C	~45 °C
	Central HP:	on		
	Decentralized HPs:	off		
	Solar Thermal System:	supplies both low-exergy and stratified storage		
Summer period (May–Oct)	CHP:	off	~45 °C	~25 °C
	Central HP:	off		
	Decentralized HPs:	on		
	Solar Thermal System:	supplies stratified storage only		

For modeling the DHN in *Dollnstein*, the object-oriented and acausal programming language *Modelica* with the software *Dymola* with versions 2018 to 2021 is utilized, as this is particularly suitable for physical modeling [30,31]. To map the DHN, a new *Modelica* library was created, incorporating-where possible-existing model components from open-access libraries. An overview of the entire model of the *Dollnstein* system is illustrated in Figure 8. The system shown is divided into four subsystems: The central district heating station, distribution network and consumers (*heating grid*), the power grid, and the high-order control. An additional block is used to transfer the simulation results to enable further evaluation.

While the thermal components are modeled in detail under the reconciliation of the measured data, the electricity grid is represented as an ideal power grid, which means that electricity fed-in and purchase is possible at any time. The model of the power grid is referred to as active power and is connected to the consumers and generators in *Dollnstein*. Voltage, frequency control, or reactive power are not modeled. Furthermore, the simulation model of the central district heating station is object-oriented and built up similarly to Figure 8. Within that component pumps and valves and their associated control systems are integrated into the sub-models of the respective heat generators. This structure allows quick and easy changes to the system. The simulation model of the central district heating station is described in detail by Ramm et al. [32].

As mentioned above, the power supply of the CHP does not match the electricity demand of the central HP, as there are severe problems with the compressors which led to an early replacement of the HP. In addition to that, it is planned to also invest in a new CHP. The main reason is that a cost-intensive, general revision is required soon. Therefore, the investigation of the sector coupling potential is made with an adapted model. This ensures the transferability of the results to similar systems.

The operator of the heating network is seeking to replace the CO_2-HP with a HP using an alternative refrigerant. As a result, there is no further use of the pre-cooling component. From measurement data evaluation, it became clear that the retrofitted pre-cooling was necessary to avoid a shutdown of the HP [29]. However, the overall efficiency or even the effective COP of the central HP was strongly affected by this. The new HP must be adapted to the current operation and utilization of the DHN. The new units are adjusted so that the total thermal power remains the same. This leads to a CHP of 166 kW_{th} (η_{el} = 0.33, η_{th} = 0.57) and thermal power of the central HP of 228 kW_{th} with a COP of 2.4. Due to the increased use of the central HP and the higher efficiency of the CHP unit, an electric self-consumption of almost 100% can be achieved. During the period considered (i.e., January–April), the HP utilizes the ground water and the solar thermal system as a heat source. Since the solar thermal system's yields are limited during winter and the temperature of the ground water doesn't vary much, the HP's COP remains stable around 2.4.

4. Sector Coupling in the Simulation Model

The following evaluation is done only in the winter period from the 1st of January until the 2nd of April 2018. After this period, the heat demand of the consumers is lower, due to higher ambient temperatures in spring and summer. The heat generators in *Dollnstein* reduce their operating time before the grid temperature of the DHN is lowered in May for summer operation.

4.1. Control by Residual Load

To identify the potential for sector coupling, the use of the heat generators is regulated based on the residual load. The residual load profile of *Germany* and the synthetic defined residual loads for the areas *Bavaria*, *Eichstätt*, and *Dollnstein*, as described in detail in Section 2.1, serve as a control signal to operate the heat generators in the simulation model. To serve the power grid, the CHP unit is operated when the residual load is high, e.g., to partially displace electricity from coal-fired power plants. When the residual load is low, i.e., when there is a surplus of RE, the central HP is operated using only electricity from the public grid. During this time, the CHP is forced to shut down. If the heat generated by the HP is not sufficient to supply the DHN and the temperature of the stratified storage is 5 K lower than the set temperature, the CHP is activated. The same control takes place during high residual load and therefore, the CHP operates-if possible-without the activation of the HP.

In order to provide the operator of the DHN with some planning abilities and fewer starts of the heat generation systems, the control is divided into 6 h of high and 6 h of low residual load. The timeframe of 6 h sufficiently depicts the morning and evening peaks. For the remaining 12 h of the day, the DHN is controlled based on the heat demand. During this time, the system does not serve the public power grid and the central HP operates simultaneously with the CHP. In terms of the stand-alone operation of the CHP operation at a high residual load, the stratified storage is raised to a much higher temperature level of 95 °C (assuming a suitable CHP capable of providing this temperature). This means that more energy can be stored so that the load can be shifted. For the HP operation, the stratified storage is not overheated, as this would reduce the COP of the HP.

4.2. Control by CO_2 Emissions

For comparison, the specific CO_2 emissions of the reference systems have to be clarified. The aforementioned reference system represents a combination of a CHP and central HP, in which both heat generators are adjusted by their electrical power/demand. As described in Section 4, the reference system is designed to simultaneously operate the HP and the CHP. In that case of self-consumption, an exchange between the heat generators and the power grid is not required.

In a first step, the specific heat generation of the reference system has to be calculated (c.f. Equation (1)). Due to the extensive gas grid availability in Germany and applicability to other regions the CHP fuel and emissions were modelled as natural gas (NG). Given 1 kWh NG, the efficiencies of the CHP (η_{el} = 0.33, η_{th} = 0.57) and the central HP (COP = 2.4) yields a total of 1.36 kWh of thermal energy (Q_{th}). In a second step, the CO_2 emissions of the thermal energy of 1.36 kWh_{th} can be determined. With CO_2 emissions of 200 g/kWh NG [28], this is equivalent to 147.1 g CO_2/kWh_{th} of the reference system.

$$Q_{th} = (\eta_{el,CHP} * COP + \eta_{th,CHP}) * \mathrm{E}_{NG} \tag{1}$$

In order to adjust to the fluctuating CO_2 emissions of the electricity mix and simultaneously have a lower CO_2 footprint as the reference system, a threshold for the control algorithm has to be determined. This should serve to operate the HP at a low emission value, and thus reduce the CO_2 footprint during power demand. On the other hand, the CHP should be operated at a high CO_2 emission value to displace electricity with a high CO_2 imprint. The threshold for the HP ($HP_{th,\ CO_2\ threshold}$) can be determined according to Equation (2). With a COP of 2.4 and maximum CO_2 emissions of 147.1 g CO_2/kWh_{th}, the HP operates below a value of the electricity mix of 352.4 g CO_2/kWh_{el}.

$$HP_{th,\ CO_2\ threshold} = COP * CO_2\ emissions\ per\ kWh_{th} \tag{2}$$

During the single operation of the CHP, the same amount of heat must be supplied as the reference system. As determined by Equation (1), the reference system supplies 1.36 kWh_{th} thermal energy by using 1 kWh natural gas. To gain the same thermal yields with a single operation of the CHP, 2.39 kWh natural gas is required. This leads to specific CO_2 emissions of 477.9 g/kWh (c.f. Equation (3)). The value is determined for the whole CHP which means a heat generation of 1.36 kWh_{th} and an electricity supply of 0.79 kW_{el}.

$$CHP_{th,\ CO_2\ emissions} = \frac{E_{th}}{\eta_{th,CHP}} * 200 \frac{\mathrm{g\ CO2}}{\mathrm{kWh}_{gas}} \tag{3}$$

In order to define the CO_2 threshold for the single operation of the CHP, the emissions of the reference system of 147.1 g CO_2/kWh_{th} have to be met. Converted for 1.36 kWh_{th}, this means that 200 g CO_2 out of 477.9 g CO_2/kWh can be allocated to the heat generation. The remaining CO_2 emissions of 277.9 g must therefore be assigned to the electricity provided by the CHP (0.79 kW_{el}), which leads to a specific value of 352.4 g CO_2/kWh_{el}. This threshold applies solely to the described reference system with its efficiencies of the HP and the CHP. Therefore, the threshold of 352.4 g CO_2/kWh remains the same for both the CHP and the HP. Figure 9 shows an overview of the described determination of the CO_2 thresholds.

$$CHP_{th,\ CO_2\ threshold} = \frac{CO_{2CHP,total} - CO_{2CHP,\ th.}}{\eta_{el,CHP}} \tag{4}$$

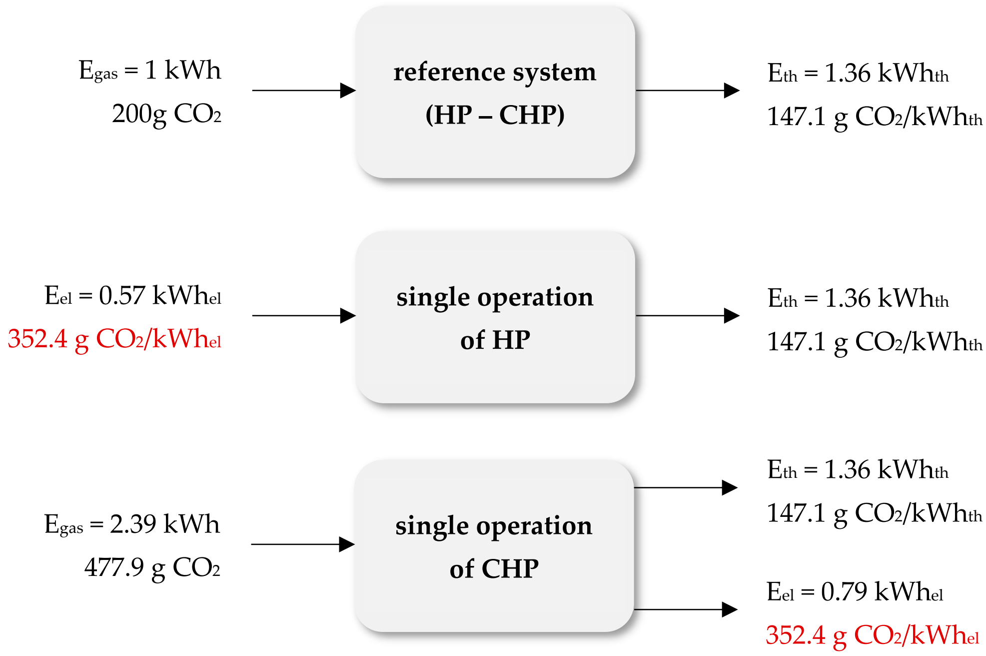

Figure 9. Methodology to determine the CO_2 threshold for the single operation of the HP and the CHP.

It must be highlighted, that this CO_2 threshold is a specific value for the DHN *Dollnstein* with a combined operation of the central HP and the CHP. This value depends on the fuel used in the CHP and the efficiencies of each unit.

The threshold of 352.4 g CO_2/kWh$_{el}$ is implemented in the control algorithm of the simulation model. This value is compared hourly to the CO_2 value of the electricity mix respectively for *Germany*, *Bavaria*, *Eichstätt*, and *Dollnstein*. For example, if the hourly value of the German electricity mix as a result of the *Merit Order* is below 352.3 g CO_2/kWh$_{el}$, the HP will be in a single operation. Whereas, the CHP will be in operation without the HP if the electricity mix has a CO_2 emission of more than 352.3 g CO_2/kWh$_{el}$. As a result of this control algorithm, a combined operation of the CHP and the HP (reference system) is not considered within this investigation.

As can be seen in Figures 4 and 6, the CO_2 curve of the electricity mix is subject to less fluctuation than the residual load curve. For this reason, a step size of 1 h is chosen for the implementation of the control algorithm instead of 6 h.

4.3. Data Availability for Control Strategies

The expected residual load can be determined free of charge by utilizing available generation forecasts of the weather dependent renewable energies (wind and solar) and the demand forecast. The error margins are expected to fall within to forecast uncertainties.

The CO_2-emission intensity can be determined by the shares of fossil fuels of the total electricity production as described in chapter 2. The share of different energy carriers in the German energy system is available as a forecast e.g., at the *eex transparency platform*. This data is gained from the market data.

For power plants using the same fuel, the difference of marginal costs is mainly determined by conversion efficiency. Therefore, typically the least efficient power plant will reduce power output or shut down at times additional generation of decentral CHPs is fed into the grid.

5. Results and Discussion

After implementing the control algorithms described in Section 4, the *Dollnstein* system can be operated to balance the residual load or the CO_2 emission curve of *Germany*, *Bavaria*, *Eichstätt*, and *Dollnstein*. The following results in Section 5.1 show the residual loads in average of the power grid during power infeed and power purchase compared to the operation of the reference system. A similar evaluation for the control algorithm to adapt the CO_2 emissions is described in Section 5.2.

5.1. Operating under Consideration of Residual Load

By adapting the control algorithm of the simulation model to the residual load, the operation time of the CHP can be partly shifted to the times with a high residual load. The reference simulation operates thermally driven in such a way that only one heat generator is activated. In case of the power infeed, a CHP-operated only DHN is the reference, in case of the power purchase, a HP-operated only system serves as reference system.

If the CHP and the HP will operate simultaneously for the reference simulation, there would hardly be any exchange with the power grid.

During the time period considered, the average residual load of Germany amounts to 34,238 MW. The power feed-in occurs at an average residual load of 42.9 GW. This represents an increase of 25.4% compared to the thermally driven reference system (c.f. Table 3). Accordingly, by considering the operation of the central HP during low residual load in Germany, the electricity load can be shifted to a lower residual load of 30.1 GW (−12.0%). Further analysis shows that for all regions (*Bavaria*, *Eichstätt*, *Dollnstein*), the heat generators can be operated to match the fluctuating residual load. However, the best results can be obtained in the view of *Bavaria* and *Eichstätt*. Adjustment to *Dollnstein*'s residual load is more difficult. The 6 hourly blocks cannot completely capture the regional short-term fluctuations.

Table 3. Change in the average residual load at all levels of consideration (*Germany*, *Bavaria*, *Eichstätt*, *Dollnstein*) during power feed-in and power purchase compared to the reference system.

	Germany	**Bavaria**	**Eichstätt**	**Dollnstein**
Average Residual Load during the considered time period	34,238 MW	5302 MW	72.6 MW	0.96 MW
Residual Load for Power Infeed	25.4%	76.5%	65.9%	37.3%
Residual Load for Power Purchase	−12.0%	−33.0%	−34.7%	−22.6%

In addition to adapting the control algorithm to the residual load to counteract the fluctuations of the energy market, CO_2 emissions are to be reduced at the same time. As can be seen in Section 2, although the two values depend on the generation of RE, they still differ in the consideration of electricity demand in the calculation of the residual load. Therefore, it is considered to what extent the operating times, regulated according to the residual load, can also be adapted to the CO_2 emission curves.

The values in Table 4 show that the CO_2 emissions of the electricity mix on average over the considered period are similar to the CO_2 emissions during the operation of the heat generators of the reference simulation.

By adjusting to the residual load, the operation of the CHP and the central HP is improved in terms of CO_2 emissions from the electricity mix. During the single operation of the CHP, which means during electricity infeed, in *Germany*, the emissions increased about 6.0%, compared to the reference system. Consequently, the electricity of the CHP can replace electricity with higher emissions in the German power grid. At the same time, the electricity demand during the operation of the central HP can be met by electricity with 9.5% lower CO_2 emissions compared to the reference system. The best results can be achieved concerning the region *Eichstätt*, with an increase of 11.5% during power infeed and a decrease of −23.7% during power purchase. However, not all levels of consideration can be adjusted to CO_2 emissions by residual load-guided control. No CO_2 savings are achieved in *Dollnstein*. The chosen 6 h blocks are not optimal for the consideration of the residual load. The short fluctuations in the CO_2 values cannot be met by this.

Table 4. CO_2 imprint of the system compared to the heat-controlled reference system by consideration of residual load. The first row reflects the CO_2 emissions of the electricity mix within the individual region throughout the whole period considered. The second row reflects the CO_2 emissions of the electricity mix within the individual region during operation of the reference system. The third row indicates the difference of CO_2 emissions between the regional electricity mix and the electricity provided in case of power infeed (i.e., CHP-only mode). The fourth row indicates the difference of CO_2 emissions between the regional electricity mix and the electricity provided in case of power purchase (i.e., HP-only mode).

	Germany	**Bavaria**	**Eichstätt**	**Dollnstein**
CO_2 imprint in average of the power grid	455.2 g/kWh	334.9 g/kWh	341.9 g/kWh	423.0 g/kWh
CO_2 imprint of the reference system	459.6 g/kWh	342.1 g/kWh	344.6 g/kWh	428.5 g/kWh
Electrical CO_2 imprint in case of infeed	+6.0%	+5.5%	+11.5%	−1.6%
Electrical CO_2 imprint in case of purchase	−9.5%	−19.7%	−23.7%	−3.0%

5.2. Operating under Consideration of CO2 Emissions

By implementing the respective CO_2 emission curves into the control algorithm of the simulation model (c.f. Section 5.2), the CO_2 impact of the heat generators can be improved significantly for all considered areas. In particular, the electricity demand of the central HP can be shifted to reduce emissions of the electricity mix from −31.3% for *Bavaria* up to −41.6% for *Dollnstein*. Compared to the previous results in Table 4, the data during power purchase from Table 5 indicates that there is no deterioration of emissions for individual considered areas. These improvements result from the shortened step sizes of 1 h to adapt the control of the heat generators to the CO_2 emissions.

Table 5. CO_2 imprint of the system compared to the heat-controlled reference system by consideration of CO_2 emission curves.

	Germany	**Bavaria**	**Eichstätt**	**Dollnstein**
CO_2 imprint in average of the power grid	455.2 g/kWh	334.9 g/kWh	341.9 g/kWh	423.0 g/kWh
CO_2 imprint of the reference system	459.6 g/kWh	342.1 g/kWh	344.6 g/kWh	428.5 g/kWh
Electrical CO_2 imprint in case of infeed	+5.8%	+26.8%	+28.5%	+12.2%
Electrical CO_2 imprint in case of purchase	−39.2%	−31.3%	−33.2%	−41.6%

In addition to the HP, the CHP can also be operated in a CO_2-oriented manner. The emissions of the electricity mix during electricity feed-in increase by an average of 5.8% for Germany and 28.5% for *Dollnstein*. Contrary to the results for power purchase, there can be identified regional differences. This is comparable to the outcomes of the operation of the heat generators considering the residual load.

However, the regional differences can be invalidated by looking at the absolute values in Table 6. This table presents the results of the CO_2 emissions of the heat generators without considering the CO_2 emissions of the electricity mix that prevails at electricity feed-in and demand. Compared to the reference system, the CO_2-managed operation can reduce the CO_2 imprint by an average of 14.7 t during the period under consideration. The savings are similar for each region. The differences between the relative (Table 5) and the absolute values (Table 6) can be explained by the CO_2 threshold of 352 g CO_2/kWh for the control algorithm of the simulation model. As soon as the hourly CO_2 value of the respective electricity mix exceeds or falls below this threshold, the CHP or central HP is activated when heat is required. In case of small changes, the relative results on average will be barely visible, but the absolute amount adds up further. The situation is different when it comes to the operation by considering the residual load. The previous results from *Dollnstein* with no reduction of CO_2 emissions can be confirmed.

Table 6. Reduction of CO_2 emissions compared to the reference system by considering the residual load and the CO_2 emissions of the electricity mix.

CO_2 Reduction Compared to the Reference System		Germany	Bavaria	Eichstätt	Dollnstein
Operation by Residual Load	in t	2.1	3.2	4.4	−0.3
	in%	2.4	3.7	5.2	−0.3
Operation by CO_2 Emissions	in t	15.5	13.5	14.3	15.6
	in%	18.1	15.9	16.7	18.3

Furthermore, the differences between residual load-managed operation and CO_2-managed operation can be identified. Overall, the values in Table 6 show that by considering the CO_2 emissions for operating the heat generators, there can be saved 9.9 t to 15.9 t CO_2 emissions compared to the residual load-managed operation. As these values are for the winter period from January until 2nd April, this reveals a high potential for DHNs.

6. Conclusions

The European power grid and also the market will be increasingly affected by fluctuations due to the electricity supplied by RE. To deal with this, sector coupling represents an important solution to this problem. Therefore, in addition to the transport sector, the heating sector plays a decisive role. As this case very clearly demonstrates, it is possible to operate heat generators with an electricity demand or output such as HPs or a CHP according to the residual load or the current CO_2 emissions of the power grid. As there is a correlation between the residual load and the CO_2 emissions of the electricity mix, there are also CO_2 savings up to 5.2% by adapting to the residual load curves. Despite the correlation, control of the heat generation according to CO_2 savings is up to 18.3% compared to the reference (heat-driven) system.

As there are physical restriction of energy transfer in the German grid, also smaller regions have been studied according to a cellular approach. However, when interpreting the regional results, especially of a rural community like *Dollnstein*, caution is required. The situation of RE in small areas depends on local circumstances. In *Dollnstein* for example, there is only one wind power plant and comparatively many PV plants. This leads to a high residual load during winter, as there is more wind than solar radiation in *Germany*.

In further research, the electricity market balancing operation of the heat generators should be transformed into a control algorithm at a real DHN. For this implementation, real-time data of residual loads are available for the operators. This has the advantage, that the time of operation can be done hourly instead of blocks of 6 h so that the adaption to the residual loads and especially to the CO_2 emissions can be improved. Furthermore, the implementation of an ideal forecast of the weather and consequently the electricity market can simplify the electricity market balanced control of a DHN.

In conclusion, the results show, that there is a high potential to save CO_2 emissions of DHNs by considering the current electricity mix. Although, this study represents the current situation of the power grid. In the future, due to the increasing share of RE and future demands (e.g., cooling), the residual load will be subject to more significant fluctuations. By contrast, the CO_2 emissions will also fluctuate in the near future but will settle at a low level in the long term.

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