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Economic evaluation of geothermal heat and power generation

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ABSTRACT

Heating and cooling is almost the half of the global energy consumption and the market volume is expected to rise significantly in the next years. Therefore, flexible systems producing heat and power will gain more interest in the future. In this study, an economic evaluation of the geothermal heat and power generation is proposed. For the evaluation the net present value (NPV) is calculated and compared to the reference case of pure power generation. To calculate the NPV, annual simulations are conducted based on a double-stage Organic Rankine Cycle and geothermal conditions in southern Germany. For the district heating network (DHN), a supply temperature of 90 °C and a return temperature of 60 °C is assumed. The peak load of the DHN is varied the range of 5 MW to 20 MW. Furthermore, different areas of the DHN are considered: an inner city DHN and a DHN in a development area. In addition, the commissioning year of the plant is varied. The results show that for a DHN in a development area the profitability of geothermal power plants can be increased by additional heat generation for all considered peak loads. For a 20 MW peak load of the DHN, the NPV is 67.5 million € and 32.2 % higher than for pure power generation. For the DHN built up in an inner city, in general, the NPV is higher than for a development area DHN. This is due to the lower investment costs because of the higher expected power density in an inner city area. Regarding the commissioning year of the power plant, as expected, the NPV is significantly lower for commissioning the plant in the future. However, this effect can be reduced by a higher peak load of the DHN.

1. INTRODUCTION

Heating and cooling represents almost the half of the global energy consumption. The market volume of heating and cooling in 2017 was 164 billion $ and is expected to increase in the next 10 years up to 264 billion $ in 2026 (Richter, 2019). Due to the fluctuating heat demand over the year and even over the day, flexible systems producing power, heating and cooling will play a more and more important role in the future. In this study the geothermal heat and power generation is considered.

In the literature, there are several studies investigating geothermal multi-generation systems. Emadi and Mahmoudimehr (2019) investigated a geothermal multi-generation system including two Organic Rankine Cycles, a refrigeration cycle and a PEM electrolyzer for hydrogen production. A parameter study is conducted to investigate the influence of different parameters on the system performance. The multi objective optimization shows that a system design with a total cost rate of 423.5 ($/hr), hydrogen production capacity of 276.1 (kg/hr) and an exergy efficiency of 24.92 % is the optimal configuration. Di Fraia et al. (2019) considered geothermal heat and power generation for wastewater treatment. Their results show that the geothermal source is sufficient to provide the required electrical and thermal energy for wastewater and sludge treatment plants.

Tempesti and Fiaschi (2013) propose a thermoeconomic analysis of a micro combined heat and power system fueled by a low temperature geothermal resource and solar energy. The aim of the study is to determine the optimal working fluid in terms of thermoeconomic considerations. The results show that R245fa leads to the lowest price of electricity generation and to the lowest overall cost of the combined heat and power plant. Van Erdeweghe et al. (2019b) considered geothermal combined heat and power concepts for two district heating networks and two scenarios for heat and electricity prices: a low price-scenario and a high price-scenario. Their results show that for the low price-scenario the conventional costing method with fixed prices for heat and power leads to the highest revenues. For the high price-scenario, the conventional costing method should also be preferred for low-temperature district heating systems. However, for higher-temperature district heating networks the exergy costing method leads to the highest revenues for the combined heat and power plant. In a further study, van Erdeweghe et al. (2019a) present a thermoeconomic optimization of different configurations for geothermal heat and power generation. For the district heating system, different temperatures and peak loads are considered. The study shows that the combined heat and power can turn unprofitable pure electricity generation projects into profitable ones with a positive net present value. In general, the series configuration is optimal. However, for high temperature district heating systems and low heat demands a configuration with heat extraction at the ORC evaporator outlet leads to higher net present values.

In previous work, different concepts for geothermal heat and power generation are investigated based on a double-stage ORC. For the district heating network, the temperature level and the peak load is varied (Eller et al., 2019a, 2019c). In this study, an economic evaluation of future scenarios in combination with different district heating network configurations is proposed. The investigation is based on the greater area around Munich in southern Germany. In section 2, the methodology for the economic evaluation is explained and in section 3 the results are presented.

2. METHODOLOGY

2.1 Annual simulation

The economic evaluation of geothermal heat and power plant concepts is based on annual simulations inspired by VDI 4655 (Verein Deutscher Ingenieure: Gesellschaft Energietechnik, 2008). The VDI 4655 defines 10 typical day categories depending on the season, the weekday and the cloudiness. For the season, winter, transition and summer time are distinguished. Regarding the weekdays, it is differentiated between workdays (including Saturdays) and Sundays (including all national holidays). In addition, for the winter and transition time, fine and cloudy days are distinguished. However, the cloudiness is negligible in the summer time. Table 1 summarizes the defined typical day categories and introduces the official abbreviations according to VDI 4655.

Table 1: Typical day categories according to VDI 4655 (Verein Deutscher Ingenieure: Gesellschaft Energietechnik, 2008)

Time of the year	**Workday W**		**Sunday S**	
	fine H	cloudy B	fine H	cloudy B
Transition Ü	ÜWH	ÜWB	ÜSH	ÜSB
Summer S	SWX		SSX	
Winter W	WWH	WWB	WSH	WSB

Germany is divided in different climate zones with corresponding test reference years (TRY). The TRY defines the frequency of each typical day category per year and per climate zone. An excerpt of the TRY is shown in Table 2. According to the corresponding TRY13 for climate zone 13, the results for the typical day categories can be scaled up to an annual simulation.

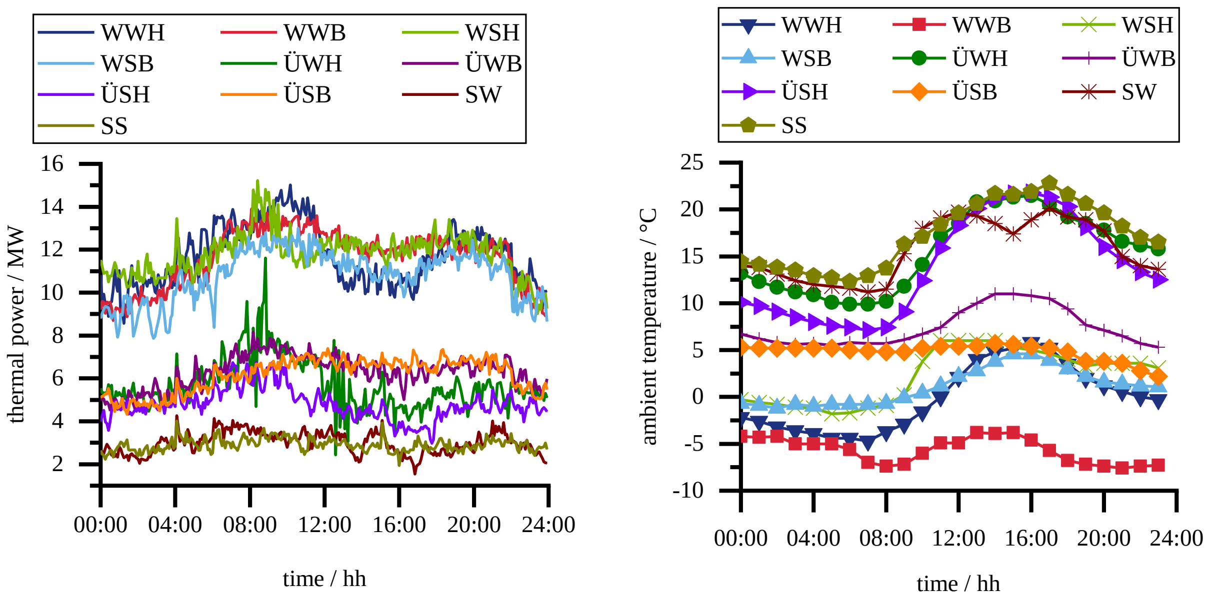
Table 2: Test reference years for different climate zones according to VDI 4655 (excerpt) (Verein Deutscher Ingenieure: Gesellschaft Energietechnik, 2008)

climate zone	**ÜWH**	**ÜWB**	**ÜSH**	**ÜSB**	**SWX**	**SSX**	**WWH**	**WWB**	**WSH**	**WSB**
…										
TRY12	27	91	8	18	104	19	23	57	2	16
TRY13	37	72	15	10	73	13	29	91	6	19
TRY14	42	81	11	15	42	7	22	115	5	25
…										

2.1.1 Heat demand profiles

To model the district heating network, heat demand profiles are developed based on real operational data of a geothermal heat plant in the South of Germany. At first, the operational data is allocated to the typical day categories. In the second step, the squared error from the mean value is calculated for each measurement time. The heat demand profile with the lowest mean value of the mean squared error is declared as the reference load profile for the relevant typical day category. A detailed description of the method is given in Eller et al. (2019a).

In addition, next to heat demand profiles, also ambient temperature profiles are needed for the simulation of a typical day category. The reference load profile is the heat demand profile, which is most characteristic for the typical day category. Therefore, the ambient temperature profile of the same day is selected as the ambient temperature profile for the corresponding typical day category. Figure 1 shows the selected heat demand profiles (a) and ambient temperature profiles (b) for all typical day categories.



(a) (b)

Figure 1: Reference load profiles (a) and ambient temperature (b) for the typical day categories

2.1.2 Dynamic simulation model

For the dynamic simulation, the software Dymola (Dassault Systèmes, 2014) is used. The models are based on the open source library ThermoCycle (Quoilin et al., 2014) and the fluid properties are calculated by CoolProp (Bell et al., 2014).

A double-stage Organic Rankine Cycle (ORC) system is considered in this study based on an existing power plant in the South of Germany. A scheme of the plant is shown in Figure 2.

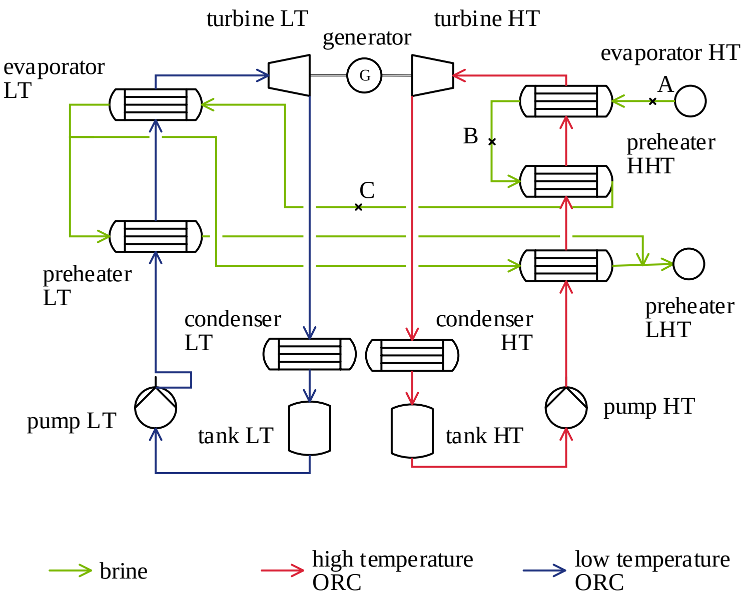


Figure 2: Scheme of the double-stage ORC power plant

The plant consists of two ORC modules: a high-temperature (HT) and a low-temperature (LT) module. In both modules, R245fa is used as a working fluid. The geothermal fluid enters the HT-evaporator and the HHT-preheater before it feeds the LT-evaporator. At the outlet of the LT-evaporator, the geothermal fluid mass flow rate is split to the LT- and LHT-heat exchanger for preheating the working fluid and is then reinjected. For condensation of the working fluid, air-cooled condensers are used in this power plant. Table 3 summarizes characteristic data of the considered power plant.

Table 3: Nominal parameters of the considered double-stage ORC power plant at the design point

parameter	**value**
thermal water temperature	138 °C
thermal water mass flow rate	120 kg/s
ambient temperature	8 °C
power rate	5.5 MW
HT-turbine inlet pressure	13.3 bar
LT-turbine inlet pressure	5.8 bar

A detailed explanation and validation of the simulation model can be found in Eller et al (2019b).

2.2 District heating network

For the district heating network, a supply temperature of 90 °C and a return temperature of 60 °C is assumed. The peak load is varied between 5 and 20 MW. Previous investigations show that the HHT-concept is the most efficient concept for the assumed district heating network (Eller et al., 2019a). In this case, geothermal fluid is coupled to the DHN at point B in Figure 2 and returns to the ORC at point C in Figure 2. Depending on the peak load and the supply temperature of the DHN, the temperature level of the thermal water at point B is not sufficient to cover the peak load and/or the supply temperature of the DHN. In this case, thermal water from point A is also coupled to the DHN.

2.3 Economic evaluation

The economic evaluation is based on the net present value (NPV) according to equation (1) (Becker, 2018):

$$NPV = -I + \sum_{t=1}^{m} \frac{r_t}{(1+i)^t} \tag{1}$$

I are the investment costs including the drilling, the plant and the district heating network. r_t are the revenues in period *t*. The interest rate is *i* and *m* is the number of periods. For the number of periods, a lifetime of the power plant of 30 years is assumed (Heberle et al., 2016). The revenues r_t are calculated by equation (2):

$$r_t = \sum_{\text{typical days}} (E_{el,gross} \cdot p_{el,t} + Q_{DHN} \cdot p_{HE,t}) \cdot n \tag{2}$$

$E_{el,gross}$ is the electrical energy provided by the plant and Q_{DHN} the thermal energy delivered to the DHN. $p_{el,t}$ and $p_{HE,t}$ are the electricity and heat prices of the period *t* and *n* is the frequency of the corresponding typical day category per year according to Table 2.

The electrical power generation from geothermal resources is funded by the German government in the Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz - EEG). Therefore, the electricity price for power generated from geothermal resources is fixed for 20 years to 25.2 ct/kWh. The guaranteed price for 20 years decreases for power plants launched after 2020 by 5 % per year. (Salje, 2018) After the EEG funding period the actual exchange price is assumed. The exchange price for electricity in 2018 is 3.8 ct/kWh (EPEX SPOT, 2nd of 2019) and for the heat price 7.4 ct/kWh (AGFW - Der Effizienzverband für Wärme, Kälte und KWK e. V., 2019). Future prices are calculated based on an inflation rate in price of 2.0 %.

The interest rate *i* is calculated by a base interest rate and a corresponding risk premium (Becker, 2018). For the base rate, the interest rate of a 10-year government bond in Germany is considered (0.46 %) (Banque centrale du Luxembourg, 2019). For the risk premium, the average return of a share of the German DAX in the last 20 years is assumed (8.9 %) (Deutsches Aktieninstitut, 2018). For a conservative estimation, the interest rate *i* is considered to be 9.0 %.

The investment costs for the drilling are estimated according to Lukawski (2014). For the heat and power plant the costs are calculated by Astolfi (2014) and Turton et al. (2013). The investment costs of the DHN heating network consist of the costs for piping, domestic connections, needed grid technology and other costs.

For the piping costs, at first the route length of the DHN is calculated. For a development area, connected load power per meter is calculated to 1.1 kW/m based on the real geothermal heat plant considered for the calculation of the heat demand profiles. For an inner city area, the power density is assumed to 2.4 kW/m (AGFW - Der Effizienzverband für Wärme, Kälte und KWK e. V., 2018). The overall connected load of the DHN is calculated by the peak load and the simultaneity factor according to equation (3).

$$\text{connected load} = \frac{\text{peak load}}{\text{simultaneity factor}} \tag{3}$$

The simultaneity factor takes into account that the maximum connected load power of all consumers is not requested at the same time. For the considered DHN, real operational data are analyzed and the simultaneity factor is calculated to 0.51. The peak load is varied in the range of 5 to 20 MW.

The costs per meter vary due to the structure of the DHN. In this study, two cases are considered: A DHN in the inner city and a DHN in the development area. The costs per meter are assumed based on the range given by Biedermann and Kolb (2014). For both scenarios, the maximum costs per meter are assumed. Exemplarily, for a peak load of 20 MW and an inner city area the costs per meter are calculated to 528.22 €/m and for a development area 285.54 €/m.

For the costs of the domestic connections, the number of domestic connections is calculated. Therefore, existing geothermal district heating networks are analyzed and the average connected load per domestic connection of 40 kW is considered. The costs per domestic connection are estimated by Clausen (2012) up to 4.200 € per domestic connection.

The costs for the needed grid technology are estimated by 7 % of the costs for piping and domestic connections. The other costs are estimated by 7 % of the costs for piping, domestic connection and needed grid technology. (Clausen, 2012)

3. RESULTS

For the scenario analysis, in this work the pure power generation is compared to the heat and power generation. Furthermore, different peak loads of the DHN and regions like inner city DHN and development area DHN are considered.

In a first step, an development area DHN is investigated. The net present values over the lifetime of the plant for peak loads of the DHN between 5 MW and 20 MW are shown in Figure 3. For the pure power generation the peak load of the DHN is equal to 0 MW. For a relatively low peak load of 5 MW of the DHN, the heat and power generation leads to a lower net present value (NPV). Compared to power generation (51.1 m€) the NPV is 7.2 % lower.

The additional heat generation is connected to higher investment costs, in particular for the set-up of the district heating network. Compared to pure power generation (32.4 m€), the investment costs are 10.7 m€ higher. Furthermore, the annual revenues can be increased by an additional heat generation. The revenues are on average up to 1 m€ higher per year in comparison to the pure power generation. The additional revenues cannot overcome the additional investment costs and, therefore, the NPV is lower than for pure power generation.

For a higher peak load of the DHN of 10 MW, the heat and power generation reaches a higher NPV than pure power generation. The NPV can be increased by 6.5 % up to 54.4 m€. The additional revenues from the heat supply overcome the investment costs for the DHN. For a 15 MW peak load of the DHN, the NPV is 19.5 % higher than for power generation. Compared to the 10 MW DHN, the NPV is 730,000 € higher. The reason for this slight improvement are the increased investment costs for the DHN. For a DHN with a peak load of 20 MW the NPV is 67.5 m€. This is an increase compared to power generation of 32.2 %.

In sum, a peak load of 10 MW is necessary to get a higher profitability of the plant by an additional heat generation.

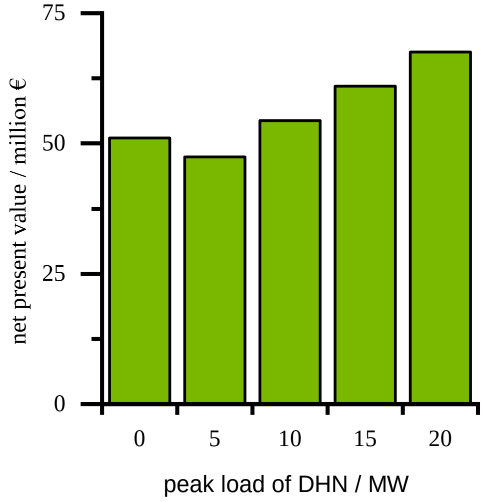


Figure 3: Net present value for an inner city area and different peak loads of the DHN

In a development area, the investment costs for the DHN are lower than for inner city area. However, the route length per connected load power is expected to be higher Therefore, Figure 4 shows the NPV for a development area and an inner city area. For both, the NPV can be increased by a higher peak load of the DHN. Compared to the development area, the NPV of the inner city DHN is higher than for a development area for all peak loads considered. For a peak load of 5 MW, the relative difference is 2.3 % (1.1 m€). By increasing the peak load, the relative difference is even higher. For 20 MW the difference is 6.8 % (4.6 m€).

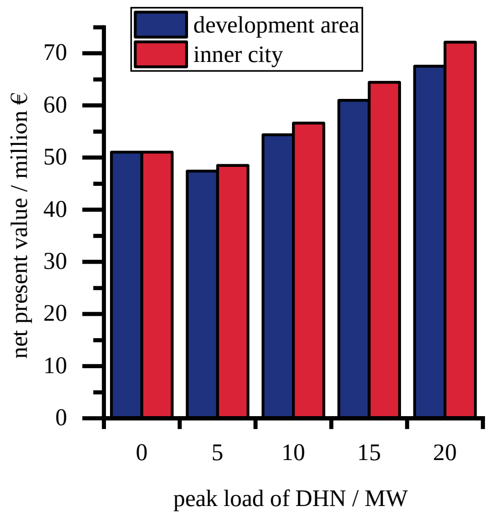


Figure 4: Net present value for an inner city DHN and a development area DHN for different peak loads.

The difference in NPV is mainly due to the investment costs for the DHN. For a development area with a power density of 1.1 kW/m the estimated investment costs for the DHN are higher than for an inner city DHN with a density of 2.4 kW/m. For a peak load of 10 MW the difference is 1.7 m€ and increases with the peak load up to 3.4 m€. For an inner city DHN, a lower power density of of 1.91 kW/m leads to the same NPV than for the development area.

In the next step, the commissioning year of the plant is varied. Figure 5 shows the NPV for commissioning of the plant in different years for an inner city DHN. For each peak load of the DHN, a commissioning year in the future leads to lower NPV, due to the lower EEG funding. In 2030, the NPV is 79.3 % lower for a peak load of 5 MW. The difference can be reduced to 30.1 % by increasing the peak load to 20 MW. Compared to pure power generation, in 2030 the heat and power generation shows a 1.8 m€ higher NPV for a 5 MW peak load. For a peak load of 20 MW the NPV is more than six times higher than for pure power. The higher the peak load of the DHN, the lower is the amount of electricity generated and the lower the revenues from electricity sales depending on EEG-funding. In contrast, a higher thermal power is delivered to the DHN, which leads to higher revenues not depending on the EEG-funding. Therefore, the NPV increases with the peak load, especially for commissioning years in the future, when the EEG-funding is significantly lower.

In 2040, the NPV up to 5 MW peak load are lower than 0. The revenues cannot overcompensate the investment costs and, therefore, these alternatives cannot be recommended. A peak load of 10 MW is needed for an economic feasible business case.

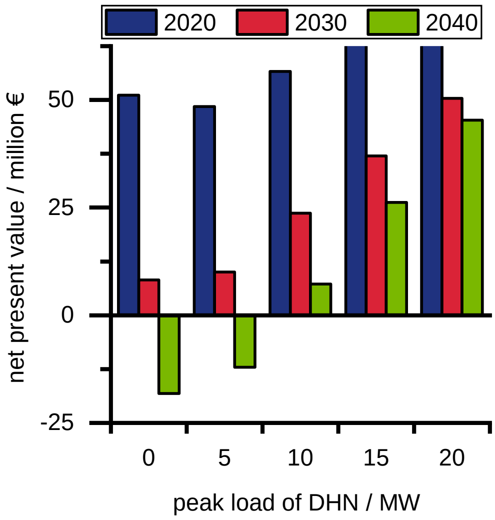


Figure 5: Net present value for inner city area DHN and different commissioning years as well as DHN peak loads.

For the development area, the results are similar. However, the decrease is in general higher than for an inner city area. From 2020 to 2030 and 20 MW peak load of DHN, the NPV is 33.1 % lower. In 2040, for 20 MW DHN the decrease in NPV is for an inner city area 30.1 %. For a development area, the decrease is 41.6 % %. The reason for that are the higher investment costs for the DHN in a development area.

In the next step, the inner city is compared to the development area. Figure 6 shows the NPV of inner city DHN and development area DHN for 2030.

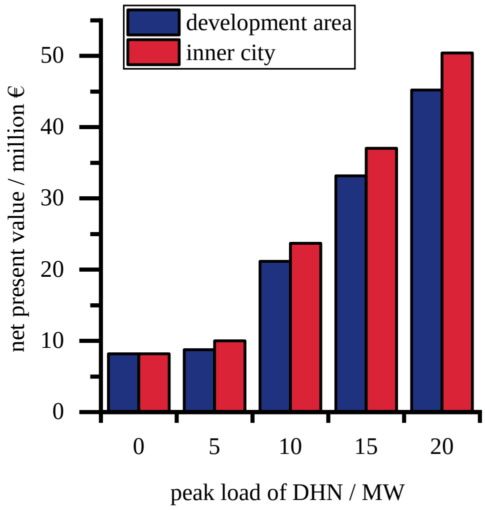


Figure 6: Net present value for inner city DHN and development area DHN for different peak loads and commissioning year 2030.

Analogous to the previous investigations, the inner city area shows higher NPV than the development area due to the higher power density. For a 5 MW DHN the NPV of the inner city area is 10.0 m€ and 14.2 % higher than for an development area DHN. By increasing the peak load up to 20 MW the difference is 11.5 %. The results for 2040 are similar to those of 2030.

In addition, Figure 7 compares the NPV of development areas for the different peak loads and commissioning years 2030 to 2040. The results show that in 2030 the NPV is positive for all peak loads, including the pure power generation. For 2040, a peak load of 10 MW is necessary to reach a recommendable investment as for the inner city DHN (see Figure 5). As shown for the inner city DHN, for the development area the differences in NPV between 2030 and 2040 also decrease with the peak load. This is due to the lower impact of the EEG funding on the overall revenues by increasing the peak load.

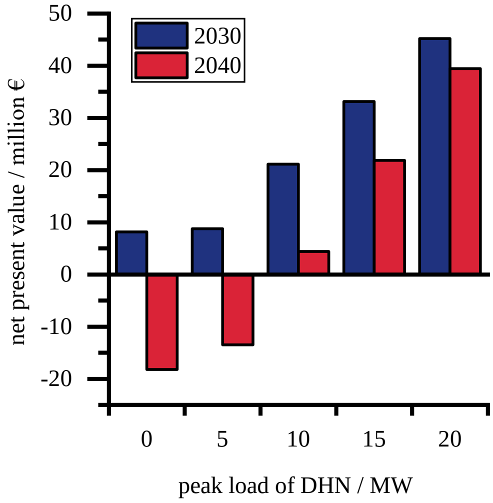


Figure 7: Net present value of development area DHN for different peak loads and commissioning years.

4. CONCLUSION

In this study, the geothermal heat and power generation is economically evaluated and compared to pure power generation. For the evaluation, annual simulations are conducted and a lifetime period of the plant is considered. For the district heating network (DHN), a supply temperature of 90 °C and a return temperature of 60 °C is assumed and the peak load is varied between 5 MW and 20 MW. In addition, different years of commissioning the plant are analyzed. The main results are summarized as follows:

- For a development area, the profitability of the power plant can be increased by additional heat generation compared to pure power generation for all considered peak loads of the DHN. The highest NPV is 67,5 m€ and 32.2 % higher than for pure power generation.
- For an inner city DHN, the NPV increases with the peak load of the DHN. Compared to the development area, the NPV is up to 6.8 % higher.
- By commissioning the plant in 2030, the NPV is decreased significantly due to the degressive EEG funding. Therefore, a combined heat and power generation can damp this effect. The higher the peak load of the DHN the lower is the decrease in NPV. Nevertheless, the NPV is still positive and therefore the investments are profitable.
- By commissioning the plant in 2040, for both DHN a peak load of 10 MW is necessary for a recommendable business case with a positive NPV.

In future work, different heat and power concepts are considered and further development scenarios for the DHN during lifetime over the power plant. In addition, different district heating networks regarding the temperature level are analyzed.

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