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Economic feasibility of supra-regional district heating networks: Addressing technical and economic considerations

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ABSTRACT

Various models exist for pricing heat in district heating networks, with most assuming that the heat supplier holds a natural monopoly position within the network. However, a supra-regional district heating network can break this natural monopoly, creating a new market with multiple heat suppliers. Operation strategies and thus pricing models for such structures are rare, often failing to reimburse the full costs incurred by heat suppliers and lacking sufficient control strategies. This paper introduces a novel heat pricing model in combination with an operation strategy that addresses all key aspects of operating these networks by implementing a merit-order bid price system based on levelized costs of heat, with caps and floors. In addition, it provides an analysis of these structures by applying the operational strategy and the novel pricing model to a case study. The results demonstrate that a supra-regional district heating network can be economically and technically integrated into the examined area without any limitations in temperature levels. This integration leads to reduced heat costs for some customers compared to scenarios without this network. Moreover, industrial waste heat suppliers and biomass plants experience a notable increase in their full-load hours.

Nomenclature

Abbreviations	
CHP	Combined heat and power
CO_2	Carbon dioxide
DH	District heating
DHN	District heating network
EU	European Union
FLH	Full-load hour
HGU	Heat generation unit
HTIWH	High-temperature industrial waste heat
IWH	Industrial waste heat
KPI	Key performance indicators
LCOH	Levelized costs of heat
MTIWH	Middle-temperature industrial waste heat
NPV	Net present value
SRDHN	Supra-regional district heating network
Variables	
C_u	Annual heat unit costs [€/a]
C_m	Annual maintenance costs [€/a]
C_o	Annual operation costs [€/a]
C_s	Annual standing costs [€/a]
C_{tot}	Annual total costs [€/a]
BP	Bid price [€/MWh$_{th}$]

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C_{CO2}	Carbon dioxide costs [€/MWh$_{th}$]
CF	Cash flow [€]
$\dot{Q}_{con}$	Connected load [MW$_{th}$]
ρ	Density [kg/m^3]
r	Discount rate [%]
T	Economic lifetime [a]
P_{el}	Electricity price [€/MWh$_{el}$]
C_{fue}	Fuel costs [€/MWh$_{th}$]
FLH	Full-load hour [h]
$\dot{Q}_{cap}$	Heat Capacity [MW$_{th}$]
$\dot{Q}_d$	Heat demand [MW$_{th}$]
$LCOH$	Levelized costs of heat [€/MWh$_{th}$]
NPV	Net present value [€]
c_p	Specific heat capacity [J/(kgK)]
Q	Total amount of heat [MWh$_{th}$]
I_0	Total investment costs [€]
S_0	Total subsidies [€]
$\dot{V}$	Volume flow [m^3/s]
Subscripts	
cos	Customer
el	Electricity
exi	Existing local district heating network

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HGU	Heat generation unit
max	Maximal
th	Thermal
k	Time-step
SRDHN	Transmission lines and a system heat generation unit of a supra-regional district heating network
t	Year
Greek	
Δ	Difference
η	Efficiency [%]
θ	Temperature [K]

1. Introduction

There is a significant global demand for heat, with approximately 50 % of the overall final energy demand attributed to heating in 2022. Notably, around 44 % of this demand was dedicated to space heating [1]. One effective way to meet this demand is through the implementation of district heating networks (DHNs). To address the challenges of climate change [2], increasing research [3–5] is focused on integrating renewable sources and industrial waste heat (IWH) into these networks. Lund et al. [6] define different generations of DHNs, ranging from the first to the fourth generation, based on factors such as network temperatures, integrated (renewable) heat sources, and efficiency. In some regions, DHNs resemble the early stages of electricity grids before transmission systems were integrated. Initially, electricity networks were independent, later connected through high-voltage transmission lines. Similarly, the next logical step for some regions is to interconnect local DHNs with heat transmission lines, following the evolution of the electricity grid and ultimately creating supra-regional district heating networks (SRDHNs) [7]. This approach is also the key distinction of SRDHNs from large-scale DHNs, which are characterized by a high number of integrated substations [8]. Additionally, SRDHNs should primarily use renewable and sustainable heat sources. However, Moser et al. [7] note that no SRDHN currently exists, as DHNs close to the definition do not rely solely on these sources. The Copenhagen DHN, however, is the closest to meeting this definition. The cost-effectiveness of heat transmission lines is demonstrated by existing lines that extend over 10 km [9]. Their larger transmission capacities, which require larger cross-sections, minimize heat losses by improving the surface-to-volume ratio, making long transmission lines a viable option for efficient heat transport. To effectively realize heating networks in a region, it is crucial that the heat generated is environmentally friendly, that the networks are lucrative for investors, and that they represent a cost-effective alternative for heat customers. Current DHNs are mainly supplied by single or few heat suppliers, leading to monopolistic control [8]. As a result, pricing models in this sector often do not reflect the competitive dynamics of liberalized markets, as discussed in detail in the following literature review. However, in DHNs like SRDHNs, the pricing model can significantly influence the prioritization of different heat sources. This, in turn, has a major influence on the analysis of the technical and economic feasibility of such networks.

1.1. State-of-the-Art

In general, the costs of district heating (DH) are based on three main factors: the connection costs, the costs of the distribution network, and the generation costs of thermal energy. This results in the following cost breakdown: a connection fee, a standing cost, and a unit cost. The connection fee is a one-time payment for linking a customer to a DHN. The standing cost comprises fixed and variable costs associated with energy supply, such as meter reading, maintenance, and keeping the connection to the network, usually paid to the network operator. The unit costs refer to the price of one unit of heat produced and therefore include the fixed and variable costs of heat generation. There can also be additional costs such as efficiency costs or flow costs [10].

Heat pricing typically faces three major challenges: significant financial risks for suppliers due to high investment costs; annual climate fluctuations that complicate heat demand calculations; and low price transparency for customers [11].

The numerous different models described in the literature for pricing a unit of heat are outlined in Table 1 categorized by regulated and deregulated markets.

In regulated markets, some of the most common models are the true cost or true cost plus models, with national independent authorities supervising prices and delivery conditions [21]. In the former model, the price of heat must equal all necessary costs of production and distribution. This is why it is sometimes referred to as cost-of-service regulation [22]. This approach secures low prices and ensures a high level of supply security, provided the DHN owner does not bypass the intended regulation. However, a disadvantage is the lack of a direct economic incentive to reduce customer prices through performance-improving actions. In the latter model, the price is based on the true cost model but also allows for higher loan costs. This model is typically used for IWH to ensure an economic incentive for companies that are not necessarily part of a DHN [12].

Furthermore, in regulated markets, a private company may manage a DHN owned by a local government through lease or authorization contracts, with heating prices and conditions set by municipal departments and approved by higher authorities [12].

In deregulated markets, the heat price can be based on different costs like marginal costs, incremental costs, or shadow prices. Marginal costs represent the costs of producing a further unit of heat, including both fixed and variable operating expenses [15,23]. Li et al. [10] also discuss the differences and the effects on the heat price between short-term and long-term marginal costs. They also indicate that using marginal costs for heat pricing can lead to over- or underpricing the non-marginal portion of heat generation. Moser et al. [14] discuss the application of marginal costs for calculating heat prices using a heat merit-order, which could result in negative heat prices due to the usage of combined heat and power (CHP) plants or other heat generation units (HGUs) with possible low marginal costs. Shadow prices also known as marginal abatement costs [24], are challenging to determine because they reflect the resource price when optimal allocation of resources is achieved at market equilibrium, which does not typically exist in reality [15,25].

Zhang et al. [16] provide a heat pricing model in a DHN by adapting the electricity value equivalent pricing theory from the electricity market. With this model, not only a single DHN is used to price heat, but other regions with different DHNs are also considered to overcome the monopoly of many DHNs. According to Li et al. [10] the model seems to be too complicated for the often small structured DHN operators.

Li et al. [11] present a model to dynamically price heat based on

Table 1
Methods for pricing heat.

Market Regulation	Model	Source
Regulated	True costs	[12]
Regulated	True costs plus	[10,12]
Regulated	Private operation under public ownership	[12]
Deregulated	Marginal cost	[10, 13–15]
Deregulated	Incremental cost	[10]
Deregulated	Shadow price	[10,15]
Deregulated	Integrated model of competitive and regulated market	[10,16]
Deregulated	A dynamic price model based on levelized costs	[11]
Deregulated	Substitution price of heat	[12]
Deregulated	Price cap based on alternative supplies	[12]
Deregulated	Energy service company market for commercial owners	[12]
Deregulated	Multi-energy markets	[17–20]

levelized costs of heat (LCOH). Since LCOH can only be calculated by knowing the annual full-load hours (FLHs) of each HGU, the described model uses a prediction model [26,27] to estimate them based on a neural network. The order in which the installed heating units are dispatched (hereinafter referred to as the order of utilization) to cover the heat demand is determined manually.

Setting the heating price based on the natural gas price is another alternative for pricing heat. However, this model carries the risk that the heating price may not accurately reflect the actual cost of heat generation, as fuel prices can vary depending on the type of fuel used. Another option is to establish a maximum price threshold. However, this can result in less incentive to lower the price through increased efficiency measures. Alternatively, to ensure fair earnings and protect customers from price hikes, an energy service company can provide investment, technology, and information for the implementation of new or retrofitted DH supplies. This includes offering a fixed heat price for several years to shield customers from unexpected price increases [12].

Multiple studies focus on incorporating different energy carriers' costs into heat pricing models. For instance, Fu et al. [17] propose a double auction electricity-heat market for simultaneous trading of electricity and heat. These systems primarily operate on the principles of a merit-order-system.

Furthermore, it is not only the pricing model that influences the costs of DHNs. Also, the efficiency and design of DHNs are crucial for minimizing heat losses and the associated follow-up costs. For example, Yang et al. [28] focus on the optimal design of DHNs. One outcome is that prioritizing the minimization of construction costs can negatively impact operational efficiency. As described by Jie et al. [29], pumping costs and heat losses significantly impact the economics of a DHN and are highly influenced by network design and construction. Van der Zwan et al. [30], optimize the heat demand in a DHN by using the thermal mass of buildings for daily storage. According to Ref. [31], smart metering can enhance system efficiency by optimizing supply temperatures at different HGUs. Valve opening strategies at substations to optimize DHN temperatures are discussed by Lin et al. [32]. For the optimized operation of DHNs, incorporating forecasting models based on neural networks can be also a valuable contribution [33].

1.2. Scope of the work

The literature highlights several factors, including network design, fluid temperature, valve opening strategies, heat losses, and heat pricing, that influence the operation of DHNs. Among these, heat pricing receives particular attention, as the operation of DHNs with multiple independent heat suppliers is predominantly influenced by the order of utilization. However, as already shown most pricing models assume that a DHN operates as a monopoly. Only a few models are specifically designed for deregulated markets with multiple heat suppliers. Furthermore, these approaches face several unresolved challenges, including issues of overpricing, underpricing, and excessive complexity. The LCOH model [11] offers a viable alternative. However, determining LCOH involves a feedback-loop-problem that must be considered: the order of utilization should be set automatically by ascending LCOH, but changing the order of utilization affects the FLHs, which influence the LCOH. In conclusion, this creates a continuous loop of adjustments. The model also assumes that the actual LCOH are always passed on to the customer, which would only happen to a limited extent in a deregulated market with a merit-order. In conclusion, most of the existing research focuses on individual solutions for the operation of DHNs, often assuming that DHNs have only a few suppliers. Therefore, this paper focuses on two key aspects: the possible operation strategy of a SRDHN and the economic viability of SRDHNs, with the latter closely linked to the former. The resulting research questions are therefore as follows.

- How can a multi-producer heat pricing model for a SRDHN be designed to determine the order of utilization?
- How can a SRDHN operate in an economic environment where the order of utilization of installed HGUs is based on the novel pricing model?
- What technical control strategies are needed to overcome challenges in the daily operation of a SRDHN under the previously introduced pricing model?
- Can a SRDHN be economically feasible under the proposed operation strategy, compared to conventional DHNs?

This paper presents a novel pricing model for SRDHNs and evaluates its techno-economic feasibility under its application. As this paper doesn't aim to propose a new market model or tariff structure for DHNs, complex investigations on regulative aspects regarding a SRDHN and roles of market players or specific questions on tariff structures are not addressed.

2. Method

The methodology chapter is organized into four main sections: first, the cost structure of SRDHNs; second the determination of unit costs to establish an order of utilization; third, the description of control strategies and fourth, the methods of evaluations and analyses for assessing the impacts of the proposed approach.

2.1. Cost structure

As discussed in the literature section, the total annual costs $C_{tot,cos}$ for DH customers consist of annual unit costs C_u (see Chapter 2.2) and standing costs C_s. The new pricing structure for SRDHNs further incorporates the annual operating $C_{o,SRDHN}$ and standing costs of SRDHNs including their system-HGU (described in Chapter 2.3). The equation for the final cost calculation is shown in Equation (2–1).

$$C_{tot,cos} = C_u + C_s + C_{o,SRDHN} \tag{2-1}$$

2.1.1. Standing costs of a SRDHN

To cover the additional costs of a SRDHN, the annual standing costs of a SRDHN $C_{s,SRDHN}$ need to be added to the annual standing costs of the already existing local DHNs $C_{s,exi}$, as shown in Equation (2–2).

$$C_s = C_{s,exi} + C_{s,SRDHN} \tag{2-2}$$

The calculation of the standing costs of a SRDHN including a system-HGU is shown in Equation (2-3), with $\dot{Q}_{con,SRDHN}$ as the total connected load of all heat-consumers across the entire SRDHN, $I_{0,SRDHN}$ as the investment costs, $C_{m,SRDHN}$ as the annual maintenance costs, $\dot{Q}_{con,cos,max}$ as the maximum connected load of the customer in question and T_{SRDHN} as the economic life time.

$$C_{s,SRDHN} = \left(\frac{I_{0,SRDHN}}{\dot{Q}_{con,SRDHN} \cdot T_{SRDHN}} + \frac{C_{m,SRDHN}}{\dot{Q}_{con,SRDHN}}\right) \cdot \dot{Q}_{con,cos,max} \tag{2–3}$$

2.1.2. Operation costs of a SRDHN

The operation costs of a SRDHN include the operation costs associated with the circulation pumps for the transmission lines, as well as the unit costs of the system-HGU. These costs can initially be based on the projected overall heat consumption for the upcoming year in the SRDHN. At the end of each year, however, they should be recalculated based on the actual heat transported, the actual electricity price, the actual energy consumption of the circulation pumps, and the updated unit costs of the system-HGU. This adjustment would allow for correcting any under- or over-pricing due to inaccurate assumptions, with the difference either deducted from or credited to the customer.

2.2. Order of utilization

As discussed in the literature section, there are different ways to price heat in a DHN and thus determine the order of utilization. To establish a new model for pricing heat in a SRDHN, the following criteria should be considered.

- Heat suppliers should be able to compete against each other in an at least partially liberalized market with fair rules.
- The heat price should be transparent for customers.
- There should be incentives to increase both the efficiency of heat suppliers' HGUs and the number of HGUs with low greenhouse gas emissions.
- There should be incentives to decrease the demand in peak load situations by (large) customers.
- It should be straightforward to implement.
- Both the profit for heat suppliers and the possible price fluctuations for heat customers should be predictable.

This work introduces a merit-order with LCOH bid prices, incorporating caps and floors.

2.2.1. Bid prices

The bid price refers to the price bid by a heat supplier when participating in the merit-order-system. As Moser et al. [14] demonstrate, a merit-order based on marginal costs can result in negative unit costs, particularly when CHP plants or waste incineration plants are involved. As a result, if these HGU types are the only types in a SRDHN, the plants may fail to recover their initial investment within the expected payback period. The term "HGU types" in this paper refers to various heat supply systems, encompassing all possible plant types, ranging from renewable HGUs to those powered by fossil fuels. To avoid such a situation the presented bid prices are based on LCOH. The final LCOH for non-private corporations can be calculated as described in Equation (2–4) [34]. Where I_o represents the total investment costs, S_0 denotes possible subsidies, $Q_{HGU,t}$ is the total amount of heat provided in the year t, r is the discount rate, $C_{o,HGU,t}$ refers to the operation and maintenance costs for the year t, with its unit expressed in euros and T is the economic lifetime.

$$LCOH_{HGU} = \frac{I_0 - S_0 + \sum_{t=1}^{T} \frac{C_{o,HGU,t}}{(1+r)^t}}{\sum_{t=1}^{T} \frac{Q_{HGU,t}}{(1+r)^t}} \tag{2–4}$$

The provided heat for a year by an HGU in question $Q_{HGU,t}$ depends on its full-load hours $FLH_{HGU,t}$ and its maximum capacity $\dot{Q}_{cap,HGU,max}$ as described in Equation (2–5).

$$Q_{HGU,t} = \dot{Q}_{cap,HGU,max} \cdot FLH_{HGU,t} \tag{2–5}$$

In a merit-order-system, bids must always be submitted for specific future time-steps. As some costs fluctuate over time, the operation costs $C_{o,HGU,t}$ in Equation (2–4) are divided into maintenance costs $C_{m,HGU,t}$, fuel costs $C_{fue,k}$, electricity prices $P_{el,k}$, and carbon dioxide (CO_2) costs $C_{CO2,k}$. This segmentation enables the determination of a specific bid price $BP_{HGU,k}$ for a particular future time-step k. The maintenance costs $C_{m,HGU,t}$, which are contained in the first term in Equation (2–6), correspond to the year t, with its units expressed in euros. The other terms of the equation, vary according to the specific future time-step. Notably, the final term of the described equation is required only for cogeneration units and incorporates the thermal η_{th} and electrical efficiency η_{el}.

$$BP_{HGU,k} = \frac{I_0 - S_0 + \sum_{t=1}^{T} \frac{C_{m,HGU,t}}{(1+r)^t}}{\sum_{t=1}^{T} \frac{Q_{HGU,t}}{(1+r)^t}} + \frac{C_{CO2,k}}{\eta_{th}} + \frac{C_{fue,k}}{\eta_{th}} - \frac{P_{el,k}}{\left(\frac{\eta_{th}}{\eta_{el}}\right)} \tag{2–6}$$

Without specific legislation, regulatory oversight, and full disclosure of all costs incurred by a heat supplier, it cannot be assumed that suppliers will bid always their actual LCOH. Therefore, floors and caps are implemented, for each time-step, as described in the following sections.

2.2.2. Floors

Floors are designed to protect market participants from non-LCOH-compliant bids that attempt to enter the market despite not covering their full costs. Such bids could displace more cost-efficient HGU types. Therefore, this limit should ensure that costly HGUs do not displace cheaper HGUs from the market. The floors are calculated for each HGU type based on the most efficient HGU of that type within the considered SRDHN. Specific rules are established for the floors to ensure fair bid prices. These rules account for CO_2 costs, fuel costs, and FLHs in Equation (2–6). The floors should always be calculated one year in advance for each quarter of the year. This allows heat suppliers to plan accordingly for the upcoming year.

Rules for CO_2 costs: For carbon emission costs the lowest price from the past year, based on the assumption that the price will increase annually, should be used. This assumption should at least apply to the European Union (EU) emissions trading system, provided that the policy's credibility remains intact and is not undermined by a crisis or political backlash [35].

Rules for fuel costs: Fuel costs are influenced by the buyer's purchasing skills and cannot be precisely predicted for the floors. As a result, for non-cogeneration systems, fuel costs are set to be zero. That ensures the floors cover at least the investment costs. Depending on the cogeneration unit type, the average market prices for electricity (baseload) and gas for the quarter in question, or the average prices for biomass or coal from the last quarter of the year preceding the next year, should be used in Equation (2–6) to determine the floors.

Rules for FLHs: They should be selected based on the maximum possible FLHs in the network, to ensure that the limit is set based on the minimum possible costs. Therefore, they can be equal to the total number of hours in a year, as long as the capacity of the considered HGU does not exceed the minimum forecasted demand for the year.

2.2.3. Caps

Caps are particularly important when the installed heat capacity closely matches the maximum heat demand in the considered SRDHN. In peak load situations within SRDHNs under such conditions, it may become necessary to utilize all installed HGUs to satisfy the demand. In such cases, bid prices may diverge from the underlying cost structure, as market participants could attempt to maximize their return on investment without concern about being excluded from the merit-order for that time-step. The caps are determined by adding a fixed bid price margin to the floors of each HGU for each quarter, one year in advance. The margin is based on the HGU with the largest price difference between its potential caps (explained below) and floors within the SRDHN. To identify this HGU, and thus calculate the potential caps, Equation (2–6) with the following rules for the cost categories described below is applied.

Rules for CO_2 costs: The maximum price observed over the past year should be considered.

Rules for fuel costs: The maximum future market prices for electricity (baseload) and gas for the quarter in question should be used. For biomass and coal, the highest price from the last quarter of the year preceding the following year should be applied.

Rules for FLHs: They are calculated by dividing the total annual heat consumption in the SRDHN region by the peak heat demand in the forecasted year.

2.2.4. Merit-order

A merit-order is employed to determine the order of utilization for each time-step, thereby calculating the unit costs. The duration of each time-step can be chosen based on the availability of time-resolved costs, prices, and demand. In the merit-order, each HGU is ranked according to its bid price for each time-step. The final unit costs for each time-step are determined by the market clearing price. The market clearing price corresponds to the bid price of the most expensive HGU still needed to meet the heat demand (from now on called "marginal-HGU") for the corresponding time-step. All HGUs with lower bids than the marginal-HGU are obligated, to supply the heat they have offered for the specified time-step. This enables an order of utilization for each time-step. Competition among heat suppliers in a potential liberalized market, driven by the merit-order, entails each heat supplier striving to offer the lowest possible prices to secure the opportunity to supply heat. The merit-order with exemplary HGUs and types, in combination with the bid price structure, is illustrated in Fig. 1.

2.2.5. Simulation approach of the merit-order

Calculating the bid price for the simulation remains challenging due to the feedback loop problem discussed in Chapter 1.2. To address this, an iteration loop, as illustrated in Fig. 2, is necessary. To start, an initial estimate of FLHs for the year in question is assigned to each HGU. Then, for each time-step, the bid prices are calculated based on the assumed FLHs with Equation (2–6). This approach allows the determination of the actual FLHs achievable with the assumed values for each HGU. The iterative process continues until the assumed FLHs align with the actual one.

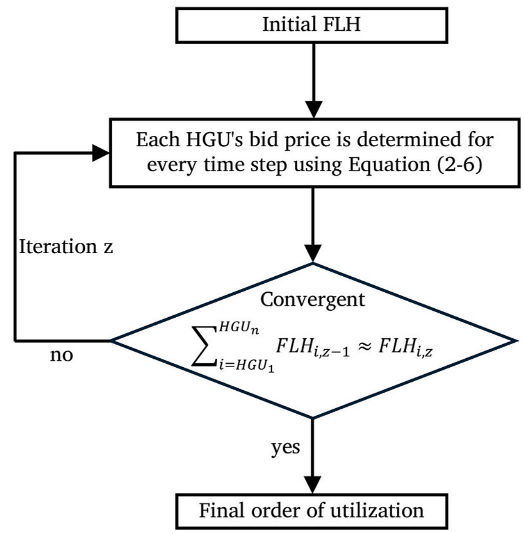

Fig. 2. Simulation approach of the merit-order.

2.3. Control strategies

Under the introduced merit-order-system, the order of utilization depends solely on economic factors, rather than specific control strategies to minimize temperature and heat losses. To enable an optimized operation with low losses three control strategies, independent of the order of utilization, are implemented: control of the supply temperature, control of the volume flow, and the implementation of a system-HGU.

2.3.1. Supply temperature

The supply temperature can be regulated by the outdoor temperature in different ways as described in Ref. [36]. A "sliding-constant" control is preferable, as it adjusts the supply temperature based on the outdoor temperature to minimize heat losses without causing supply temperatures that are too high or too low. However, this control concept lacks key SRDHN characteristics, such as varying maximum supply temperatures across HGU types. To consider this, it should ensure adherence to the specified supply temperature curve only up to each HGU's maximum possible supply temperature. Beyond that, the supply temperature should remain constant as the outdoor temperature drops, until rising outdoor temperatures permit a return to the specified control curve.

2.3.2. Volume flow

To address the challenges posed by the introduced order of utilization, three operation modes, as illustrated in Fig. 3, are implemented at the substations. In the following, the term "substation" refers to the heat exchangers connecting the heat transmission lines to the customers,

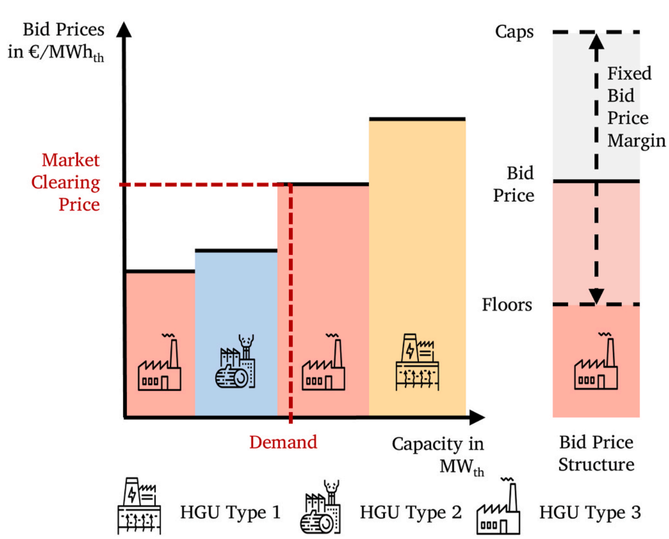

Fig. 1. Merit-order-system.

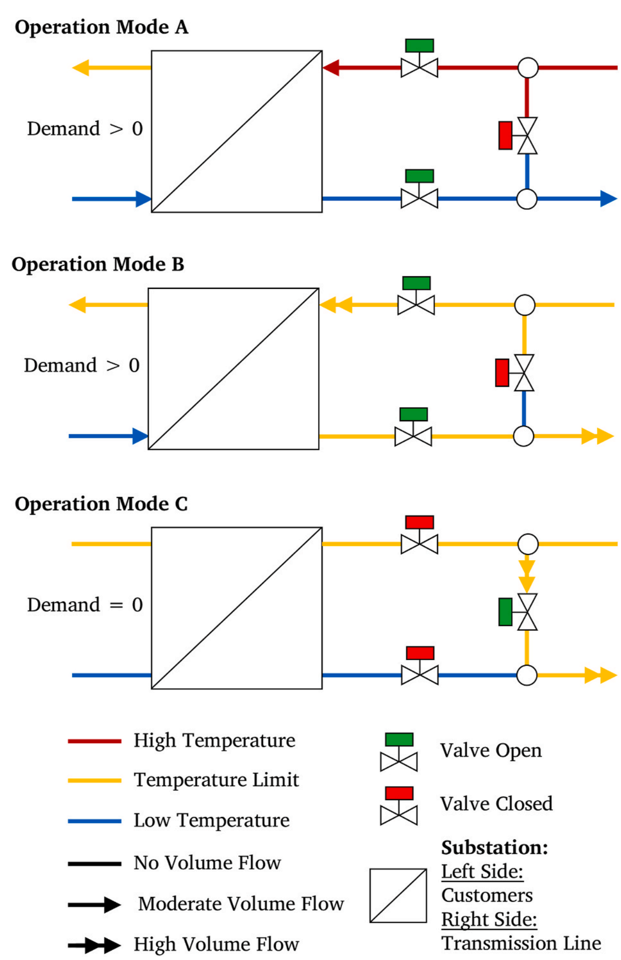

Fig. 3. Operation modes to control the volume flow.

whether local DHNs or large end users.

Operation mode A: This operation mode is designed to meet the heat demand at the substation while simultaneously achieving the desired return flow temperature, ensuring optimal operation with minimal heat losses. Therefore, it is necessary to regulate the volume flow $\dot{V}$ and to measure the temperature of the fluid in the pipes at the substation. The flow to be regulated can then be determined by using Equation (2–7). Where $\dot{Q}_d$ is the heat demand, ρ is the density and c_p is the heat capacity of the fluid and $\Delta\theta$ is the temperature difference between the feed flow temperature and the desired return flow temperature.

$$\dot{V} = \frac{\dot{Q}_d}{\rho \cdot c_p \cdot \Delta\theta} \tag{2–7}$$

Operation mode B: In SRDHNs, where a local DHN can operate autonomously with their installed HGUs for extended periods, the temperature in the supply lines between the substation and the transmission lines can drop. To avoid such situations, the operation mode B must be implemented by introducing a lower feed flow temperature limit at the substation. When the temperature falls below this limit, while there is a heat demand at the substation, operation mode B is activated. In this mode, the volume flow of the feed flow is increased to expedite the delivery of hotter fluid to the substation. This adjustment reduces the temperature difference between the feed and return flows by allowing higher return flow temperatures, which in turn increases the volume flow as governed by Equation (2–7).

Operation mode C: Operation mode C is similar to B, with the key difference being the absence of heat demand at the specific substation. As a result, the feed flow must be redirected directly into the return flow to enable a volume flow.

2.3.3. System-HGU

The system-HGU is essential to cover the heat demand in special situations. On the one hand, the HGU must have a high supply temperature to compensate for the inertia of the heating network and, in other situations, to quickly increase the temperatures in the network for the handling of operation modes B and C. On the other hand, it must be capable of compensating for unexpected heat demand and heat losses.

2.3.4. Simulation approach of the operation strategy

For the simulation of the operation strategy, a use case and a load flow calculation are required, with the load flow calculation needing to be capable of simulating time and spatially resolved SRDHNs. Such a load flow calculation could be the method described in Ref. [37]. This method employs a quasi-dynamic approach that accounts for the thermal inertia of hot water in DHNs. The specifics of which input data is needed and how it is determined for a load flow calculation are thoroughly described by Refs. [3,37]. In this paper, the method applied is based on the following assumptions for the thermal model [37].

- The temperature and velocity profiles are axially symmetric.
- No thermal stratification occurs in the radial direction.
- No thermal diffusion occurs in the axial direction.
- Material properties remain constant.
- Water's density, heat capacity, and kinematic viscosity are constant.

In essence, the necessary input data comprise the network structure represented as a node-edge graph, the diameters of the pipelines, the locations of HGUs and consumers, the installed capacities and the temporal availability of the HGUs, and a temporally and spatially resolved heat demand profile and ambient temperature.

2.4. Methods of evaluations and analyses applied

The analysis of the SRDHN can be divided into technical and economic parts. Technical key performance indicators (KPIs) for SRDHNs, are already widely investigated by Steinegger et al. [3]. They include temperature distribution, linear heat density, carbon footprint, and primary energy demand. Given the importance of water temperature for both feed and return flow in SRDHN operation, this paper focuses on this KPI for the technical analysis.

For the economic evaluation of the implemented merit-order-system, the applied caps and floors are compared with empirical values. Additionally, the NPV method is used to determine whether connecting an HGU type to a SRDHN is economically viable. The NPV [38] can be calculated as shown in Equation (2–8). Where CF_t denotes the cash flow for each year t of the economic lifetime T. I_0 represents the total investment costs, and r signifies the discount rate.

$$NPV = -I_0 + \sum_{t=1}^{T} \frac{CF_t}{(1+r)^t} \tag{2–8}$$

In addition, the unit costs of each timestep can be an indicator for heat suppliers to determine whether the connection to a SRDHN is economically beneficial or not. The potential advantage of a SRDHN for customers can be evaluated by comparing the total annual costs for customers, both with and without a SRDHN implementation.

3. Case study

In the following case study, an exemplary concept of a SRDHN in Styria, Austria, which was conceptualized by Steinegger et al. [3], corresponding to scenario S2022S, is analyzed. However, this scenario has been further refined for the presented work, so there may be slight deviations in the heat capacity values. It describes the connection of existing HGUs and local DHNs in the examined area for the year 2022 via 266 km of heat transmission lines (Fig. 4). The used HGUs are described in Table 2. Natural gas and oil boilers are excluded from the scenario.

3.1. Investment costs of the SRDHN

The investment costs for the SRDHN of the presented case study are distributed among three main categories, with the respective shares in total costs as follows.

- Installation of the pipe network (95 %)
  - o Pipe material inclusive laying work
  - o Civil engineering
  - o Insulation works inclusive material
  - o Ancillary costs (special constructions, measurements, data cables, x-ray inspections, leakage tests)
  - o Planning costs
- Installation of circulation pumps (4 %)
- Costs of the hydraulic separation of the transmission lines (1 %)

The cost calculation is primarily based on data from projects, that took place in the years 2022 and 2023, undertaken by a prominent Austrian DHN operator [39], along with data provided by the company Isoplus [40]. The following assumptions and scaling were applied to the cost calculation.

- Piping costs were scaled up from a diameter larger than 0.6 m.
- Various cost factors, including floor damage, special structures, pump houses, and excavation work, were calculated under specific assumptions and consolidated into different categories.
- Some challenging-to-quantify costs, such as some individual ancillary costs, costs for permits, costs for special components, or planning costs were assumed with a flat-rate factor.

The total costs of the SRDHN are calculated to be 617.833 Mio. € or 2321 €/m for the year 2022, if each component of the transmission line

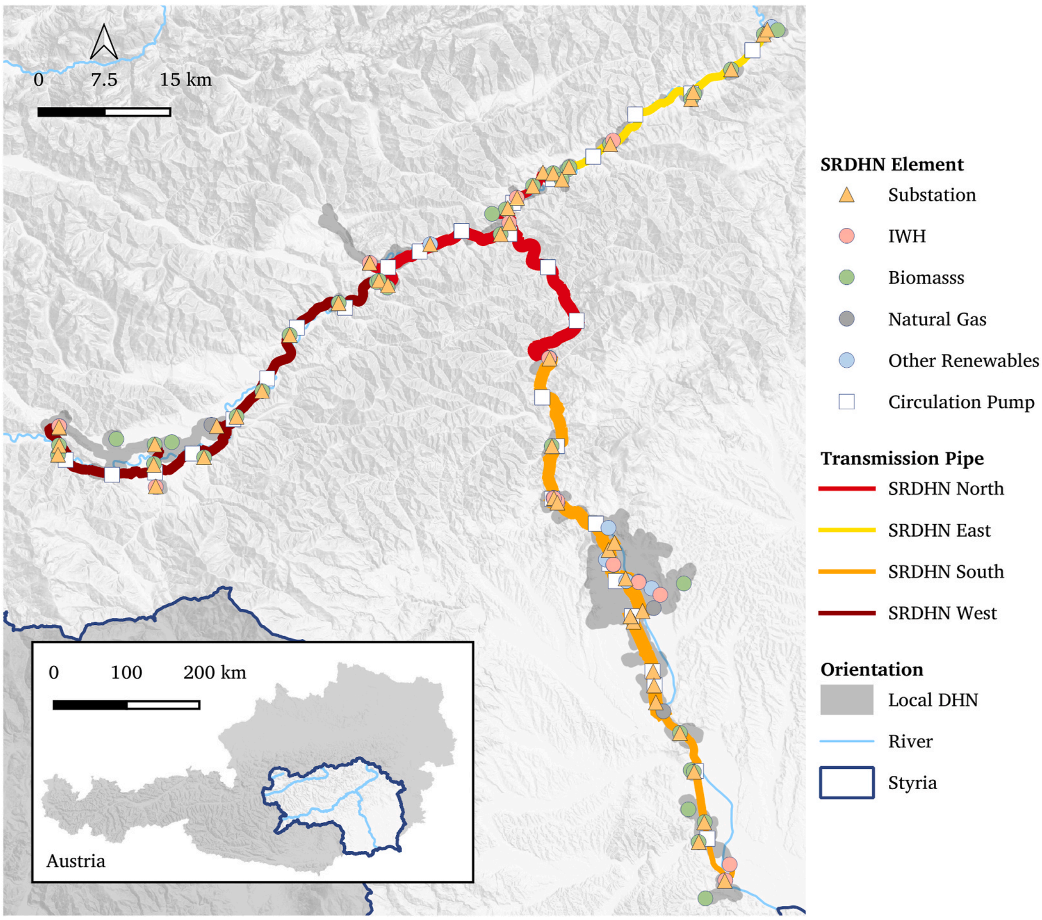

Fig. 4. Case study: SRDHN in Styria.

Table 2
Key Information of the installed HGUs in the SRDHN in Styria.

HGU Type	Quantity	Peak Power	Investment costs[a]	Subsidies	Economic lifetime	Discount Rate	C_m
		MW_{th}	Mio. €	%	a	%	%
HTIWH	17	223.250	66.611	30	10	6.5	2.75
MTIWH	1	11.500	7.649	30	10	6.5	2.75
Biomass	32	112.474	67.653	25	20	6.5	2.75
Biomass/Biogas CHP	4	27.595	25.566	35	15	6.5	2.75
Solar Thermal	5	20.070	8.924	45	20	6.5	2.75
Geothermal	1	0.110	0.223	30	30	6.5	2.75
Waste Incineration	1	5.000	2.756	30	10	6.5	2.75
Natural Gas CHP	3	437.600	579.483	0	20	6.5	2.75
System-HGU	1	40.000	13.548	25	20	6.5	2.75
SRDHN	1	–	617.834	0	30	6.5	2.00
Total	**65**	**877.599**	**1390.247**	-	-	-	–

[a] Costs at the time of construction; Including connection costs to the SRDHN (based on the year 2023).

needs to be newly constructed.

3.2. Investment costs of HGUs

To get the investment costs of high-temperature industrial waste heat (>100 °C) (HTIWH), middle-temperature industrial waste heat (50 °C–100 °C) (MTIWH) in combination with a heat pump and biomass plants, specific cost functions are worked out as shown in Fig. 5. These cost functions represent the specific investment costs per heat capacity unit for a new HGU. As the installed heat capacity increases, the specific investment costs decrease due to economies of scale. The resulting costs for the case study under consideration are adjusted to the year of installation using the construction price index [41] of the last 30 years for Austria. These costs are guide costs used for further calculations but may differ from the actual investment costs.

The investment costs for biomass CHP-, solar thermal energy-, and geothermal energy plants are determined based on actual values [44, 45]. The costs for waste incineration plants are based on the same function as for HTIWH. Values for natural gas CHP plants are determined according to the cost functions described by Ref. [46] or based on actual costs. The additional investment costs for connecting the HGUs to the SRDHN are included in the overall investment costs of each HGU by using data from Ref. [39].

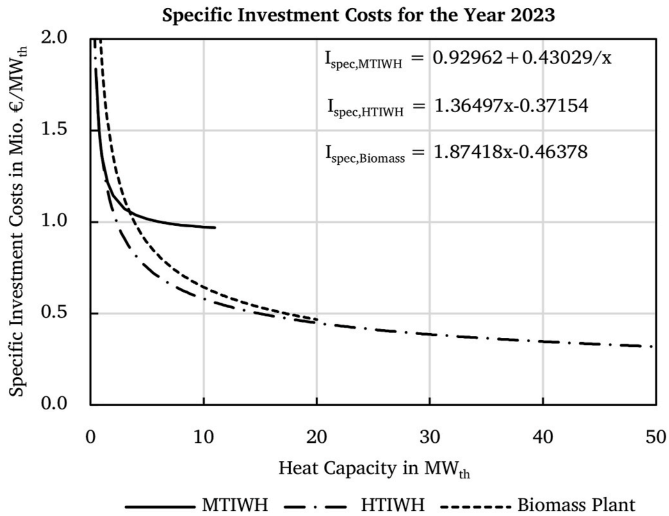

Fig. 5. Specific cost function for the year 2023: HTIWH based on actual investment costs in the case study area; MTIWH based on [42]; biomass plants based on [43].

3.3. Additional factors for calculating the bid prices

To calculate the bid prices, various data specific to the conditions in Austria are used. Table 2 presents the accumulated values for the different installed HGU types. Subsidies are calculated as a percentage of the investment costs using the values published by Ref. [47]. In addition, EU funding of 16 million euros has been identified for the Mellach CHP plant [48]. The economic lifetime of the HGU types is acquired from Refs. [49,50]. The discount rate depends on several factors, as described in Ref. [51]. In the presented case study, a discount rate of 6.5 % is assumed. The maintenance costs for the various HGU types are based on a percentage of the total investment costs, for simplicity's sake. A reference value within the range of the maintenance costs for biomass plants [52] is applied to the maintenance costs of all HGU types.

Further costs, such as CO_2 and fuel costs, are determined with a time resolution of 15 min for the year 2022. Whereby the wood chip costs are provided by Ref. [53], the electricity costs are provided by Ref. [54], and the gas and CO_2 prices are based on data from Ref. [55]. In addition, the grid fees for electricity [56,57] and gas [58,59] are also considered. Efficiencies are based on actual values and calculated values for biomass provided by Ref. [60]. The future market prices for electricity and gas are based on data from Ref. [61] for baseload front-quarter +3.

4. Results

The next section presents the simulation results for the year 2022 and the described case study using the newly implemented operation strategy. Further technical details on other KPIs related to the case study discussed earlier can be found in Steinegger et al. [3], as their technical analysis results closely align with the case study in this paper.

4.1. Economic analysis

The economic analysis examines the implemented merit-order, its restrictions, and the resulting costs. Fig. 6 shows the temporarily resolved unit costs of the year 2022 based on the merit-order described in Chapter 2.2 and the energy prices described in Chapter 3.3. In 2022, significant price fluctuations were observed in both natural gas prices and electricity prices, driven by the crises due to Russian aggression in Ukraine. These fluctuations have made it necessary that the caps frequently came into effect during periods of high heat demand (first and fourth quarter). These caps follow the rules outlined in Chapter 2.2

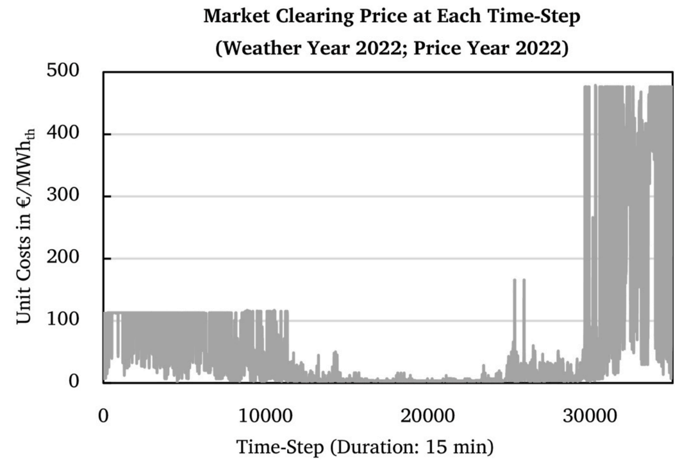

Fig. 6. Market clearing prices.

and are set individually for each quarter. The specific caps for the use case under consideration are presented in Figs. 8 and 7 by combining the fixed bid price margin with the floors. In quarter two and three, low unit costs (3 €/MWh$_{th}$ - 15 €/MWh$_{th}$) can be observed, primarily due to the low heat demand during these periods, which allows for the use of only the most cost-effective HGUs (mainly IWH) to meet the demand.

4.1.1. Evaluation of the floors

Fig. 7 shows the floors for different HGU types over the year 2022 and the actual minimum heat prices of local DHNs in the region examined. Regarding the floors: While cogeneration units are influenced by energy price fluctuations, the floors for other HGU types remain constant throughout the period. For biomass- and biogas-fueled cogeneration units, the floors decrease from quarter one to quarter four, as electricity prices rise more sharply than biomass prices. In contrast, the floors for natural gas-powered cogeneration units increase, reflecting the effects described in the evaluation of the caps. Regarding the heat prices: Compared to the actual minimum heat prices of the local DHNs the floors for all HGU types in the case study region remain below these values. This suggests that the SRDHN could offer a more cost-effective alternative to existing heat prices.

4.1.2. Evaluation of the caps

As shown in Fig. 6 the caps increase significantly from quarter one to quarter four. This increase is due to a corresponding rise in the fixed bid

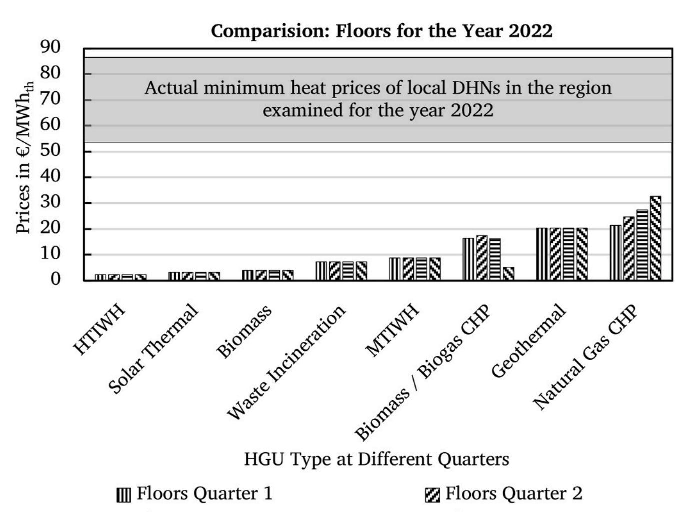

Fig. 7. Evaluation of the floors.

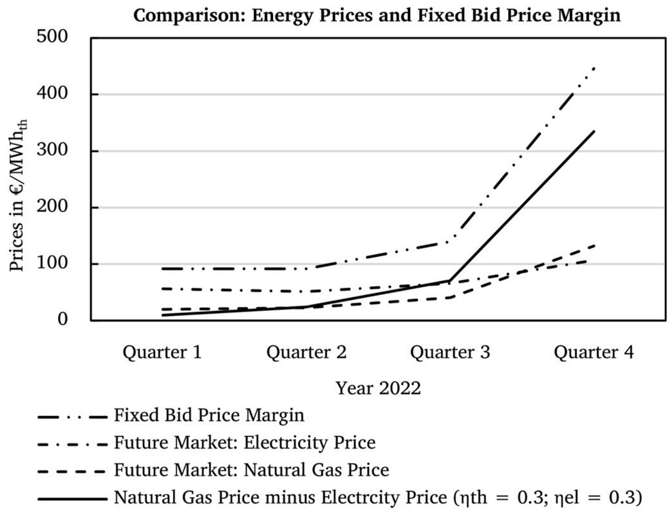

Fig. 8. Evaluation of the fixed bid price margin.

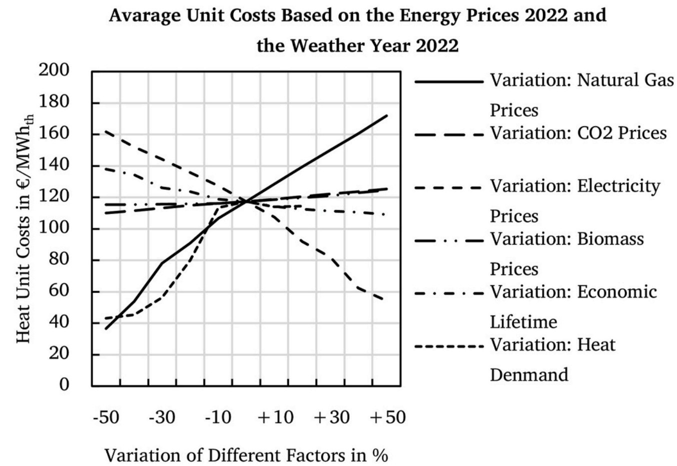

Fig. 10. Sensitivity analysis of the unit costs.

price margin over the same period, as illustrated in Fig. 8. The primary factor behind this is the substantial increase in spot market natural gas prices relative to spot market electricity prices. When considering the efficiency of cogeneration plants (with typical thermal and electrical efficiencies at 30 % each), an increase in natural gas prices has nearly a threefold effect on the bid price margin, while a rise in electricity prices results in a direct, one-to-one effect on the margin. This is also evident from Equation (2–6). As a result, the bid price margin increases sharply, leading to the rise in the caps. This is particularly significant since natural gas cogeneration units contain the HGU with the largest bid price margin in the generation mix and thus drive the fixed bid price margin.

4.1.3. Analysis of the unit costs

Fig. 9 shows the one-year average unit costs of the SRDHN, including a 10 % markup for the market operator. It compares these costs to existing average heat prices of local DHNs, weighted by heat consumption, for the years shown. The data, therefore, can be found in the literature [62,63]. The heat costs of the SRDHN are in the lower range of existing heat prices.

Since different factors significantly impact the unit costs, the following section performs a sensitivity analysis, as shown in Fig. 10. The 2022 State serves as the reference scenario for the sensitivity analysis, matching the described scenario S2022S. From this baseline, the values are adjusted accordingly. The results indicate that natural gas prices, electricity prices, economic lifetime, and heat demand have the most significant impact on unit costs according to the proposed pricing model. The significant influence of natural gas and electricity prices arises because natural gas-based CHP plants are the marginal-HGUs in high heat demand periods. The impact of the economic lifetime is straightforward: shorter payback periods lead to higher LCOH. The effect of heat demand is due to fewer high heat peaks reducing the need for heat from natural gas cogeneration units. This effect is particularly noticeable with a −50 % variation, where the unit costs settle around 45 €/MWh$_{th}$, aligning with the LCOH of biomass plants, which then take on the role as marginal-HGUs in high-heat demand periods. The variations in heat demand are limited to +20 %, as no additional capacities are available beyond this range. The small effect on the unit costs from the increased heat demand is because the marginal-HGU in the merit-order largely remains unchanged because of its high capacity, and the increase in heat peaks is not that high due to the already high amount of heat peaks in the reference scenario (2022 State). The CO_2 price plays a minor role since CO_2 is still too cheap. Even a 50 % increase would have no greater impact than a 10 % rise in gas prices.

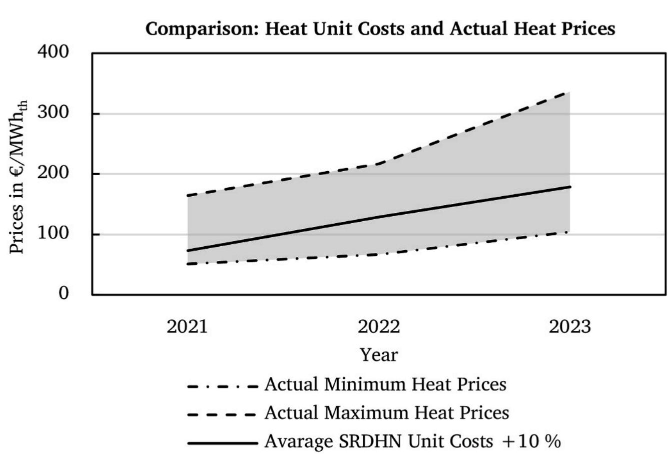

Fig. 9. Comparison of the unit costs.

4.1.4. Analysis of the total annual costs

The results, presented in Fig. 11, show the total annual costs, based on the cost structure described in Chapter 2.1, for an average household (connection capacity: 0.005 MW$_{th}$; annual heat consumption: 11.700 MWh$_{th}$). A key finding is that the additional annual costs incurred by the

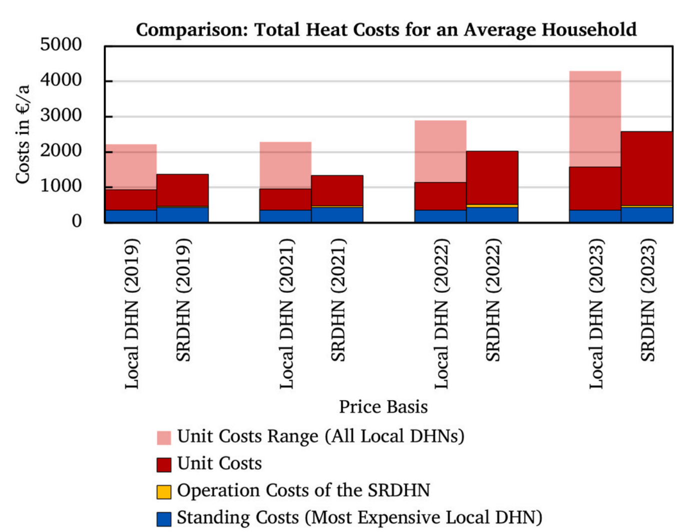

Fig. 11. Comparison of the costs for an average household (connection capacity: 0.005 MW$_{th}$; annual heat consumption: 11.700 MWh$_{th}$).

implementation of the SRDHN are relatively small across all four years. The total annual costs are significantly lower than the costs of the local DHN with the most expensive heat price of the examined region. For instance, based on prices for 2023, a household in the local DHN with the most expansive heat price would have paid about 44 % more compared to the results of the presented model. However, some local DHNs can provide heat at lower prices. This situation could change in the future if natural gas is replaced by IWH or biomass.

4.1.5. Comparison of the NPV

The influence of the SRDHN on the NPV of each HGU type (Case 2) with a higher total heat capacity than 25 MW_{th} (the impact of the other types is negligibly small and therefore not representative) is shown in Fig. 12 and compared to the NPV of installed HGUs as they currently operate without a SRDHN (Case 1). The revenues considered in this study, and consequently the cash flow, pertain solely to the heating sector; electricity revenues from cogeneration plants are not included. The focus is primarily on comparing the two cases rather than ensuring the absolute values are entirely accurate.

For the calculation of Case 1, specific assumptions were made. The data for 2022 is used for each year of the economic lifetime due to the unavailability of data for subsequent years. The fuel costs of the DHNs are based on average prices from the year 2022 and the FLHs used for the HGU types correspond to the average one described by Ref. [3]. However, these average values can be skewed by backup HGUs that are seldom used in Case 1. This distortion is particularly evident in the case of biomass HGUs, where low FLHs are partly due to their frequent role as backup units. The FLHs of biomass CHP plants in Case 1 are mainly driven by their role in drying processes, requiring year-round operation. Consequently, the revenue assumptions may also not fully capture their actual earnings. As shown in Fig. 12 for Case 1, the NPV can vary depending on the minimum and maximum heat prices of all examined local DHNs.

The results indicate that all four types would benefit from the implementation of a SRDHN. IWH mainly benefits from a significantly higher number of FLHs. Additionally, the higher market clearing price during periods of high heat demand makes the use of the other HGU types more profitable.

4.2. Technical analysis

Fig. 13 indirectly illustrates both the supply temperature control in relation to the outdoor temperature and the volume flow control at the substations.

The red line in the figure shows the maximum supply temperature of

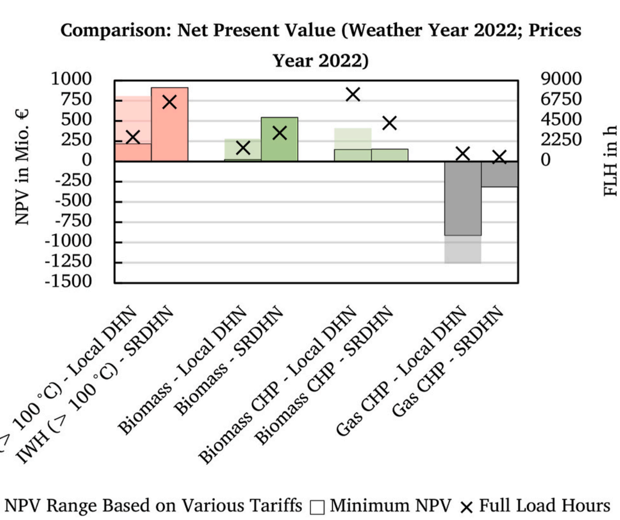

Fig. 12. NPV of various HGU types.

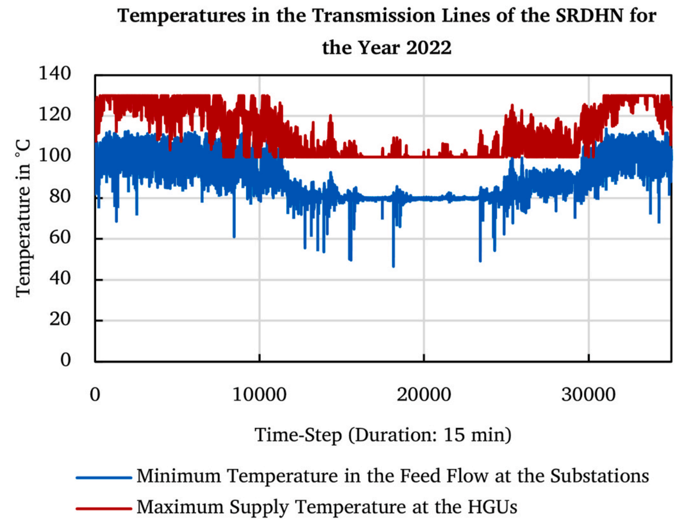

Fig. 13. Temperatures in the SRDHN.

the HGUs in the overall SRDHN at each time-step. As shown, this temperature is higher during the colder seasons than in the warmer seasons, aligning with the sliding-constant supply temperature control.

The blue line in the figure shows the minimum feed flow temperature at the substations in the overall SRDHN. The lower temperature limit for volume flow control, as described in Chapter 2.3, is set at 90 °C during the cold season and at 80 °C during the warm season. Whenever the temperature slightly drops below these limits, the control measures increase the volume flow to raise the temperature. The few significant temperature drops occur when the fluid in the transmission lines cools down mid-transmission, caused by reduced heat transmission demand in specific sections of the SRDHN, and then reaches the substation. However, these drops are effectively managed by the control system within a single time-step, as demonstrated in the figure.

Furthermore, the results show that a linear heat density of 6.0 $MWh_{th}/(m*a)$ can be achieved for the transmission lines in the SRDHN.

5. Discussion

This paper introduces a novel pricing model designed to address the challenges of pricing heat in a multi-producer environment. It incorporates a merit-order-system based on LCOH, with built-in price caps and floors. To enable the daily operation of the SRDHN, the model integrates an operation strategy that includes a volume flow control, a supply temperature control, and a system-HGU. The presented simulation demonstrates that a SRDHN can operate without technical restrictions in supplier selection. This suggests that alternative strategies for determining the order of utilization could also be applied without compromising the secure coverage of heat demand.

The presented merit-order-system supports deregulated markets, by fostering greater liberalization compared to pricing models like true costs [10] or true costs plus [10,12]. Compared to models like [14], which rely on a merit-order based on marginal costs, the presented model accounts for the full costs of heat generation. However, a limitation of this model is that it does not include a bidding strategy for multi-energy markets, as proposed by Ref. [17]. Instead, the influence of other energy markets is indirectly captured through bid prices, particularly the fuel costs, in the LCOH.

The simulation results in minimal transmission heat losses, confirming the findings of [3]. Consequently, the system maintains a high linear heat density of 6.0 $MWh_{th}/(m*a)$. The significance of this high value becomes particularly evident when compared to conventional DHNs. This is illustrated by Ref. [64], where all 377 DHNs shown, have a lower linear heat density than 6.0 $MWh_{th}/(m*a)$.

The proposed pricing model enables innovative market strategies, such as comparing heat and electricity prices in cogeneration units. The large scale of SRDHNs could also help balance heat demand year-round. This is possible because SRDHN transmission lines can connect to industrial heat sources and sinks and seasonal heat storage. For instance, industrial heat sinks can include the demand for steam. During low-cost heat periods (typically summer), these industrial sites or storage systems could absorb heat, while in winter, they could sell stored or generated heat to the network when prices rise.

This work shows that integrating a SRDHN is economically feasible without supply issues, but it also raises new research questions. For example, new market strategies enabled by the SRDHN need further development and analysis. The impact of weather-year variations on heat costs also require investigation. Additionally, the integration of a SRDHN and the new pricing model affect existing network contracts and market designs, raising legal challenges.

6. Conclusion

This paper presents the design of a heat pricing model for a multi-producer DHN to determine the order of utilization. Additionally, it outlines the necessary operational strategies for implementing the proposed pricing model. The key findings indicate that a SRDHN, combined with the proposed pricing and operational strategy, can be economically beneficial for both heat suppliers and customers while integrating seamlessly without technical constraints related to temperature. Compared to standard DHNs, SRDHNs fundamentally change supply dynamics. In conventional DHNs, a single HGU operator covers in many times both base and peak loads, limiting FLHs and revenue. In SRDHNs, higher heat demand allows multiple operators to be responsible for the base load, increasing FLHs, while peak load HGUs receive better compensation under the presented price model. This setup enhances profitability for operators and lowers annual heat costs for customers through reduced base load prices. SRDHNs, with the proposed pricing model offer numerous new possibilities that can already be estimated but will show their full potential with integration.

CRediT authorship contribution statement

Josef Steinegger: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Formal analysis, Data curation, Conceptualization. **Stefan Stering:** Methodology, Data curation. **Thomas Kienberger:** Writing – review & editing, Supervision, Methodology, Conceptualization.

Declaration of generative AI and AI-assisted technologies in the writing process

During the preparation of this work, the authors used ChatGPT 3.5 to improve the readability and language of the manuscript. After using this tool, the authors reviewed and edited the content as needed and take full responsibility for the content of the published article.

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Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

The data that has been used is confidential.

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