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# Incentivising flexible power-to-heat operation in district heating by redesigning electricity grid tariffs

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ABSTRACT

The Danish district heating sector constitutes a large potential for power-to-heat technology utilisation and thereby for increasing energy system flexibility and integration of the heat- and electricity sectors. Though the potential is there, it is uncertain whether the current flat-rate electricity grid tariff structure best incentivises a flexible integration. This study investigates how a redesign of the current flat-rate electricity grid tariffs influences the business-economic incentive for flexible power-to-heat operation in a district heating area, and how tariff schemes can incentivise increased integration of local wind power. The simulation tool energyPRO is used to investigate the influence of three redesigned tariff schemes; a flat-rate tariff reduction, a fixed time-of-use tariff scheme and a dynamic tariff scheme. It is concluded that the redesigned tariff schemes show potential for improving business-economic viability of flexible power-to-heat operation and increased integration of variable renewable electricity. However, measures and careful planning must be undertaken in the design of future tariff schemes to ensure that the necessary income for grid operators remains in place. The study thus suggests a redesign of the current tariff scheme and provides policymakers with tangible results of how a district heating company is affected by changes to the structure of electricity grid tariffs.


## 1. Introduction

Ensuring energy system and power system flexibility is a tremendous challenge to the integration of increased variable renewable electricity (VRE) in the transition to renewable energy systems [1]; a challenge that requires both technological advancements, regulatory changes, and new market mechanisms [2].

The concept of flexibility and its importance is discussed avidly in both academic research, governmental regulation, and political strategies, but regardless, no universal definition has emerged [3]. Traditionally, the term flexibility has been used solely to describe the flexibility of the electricity sector, e.g. the ability of power plants to maintain and balance voltage and frequency [4], but with increasing shares of VRE more flexibility options and mechanisms are needed [5]. This is evident in previous studies finding that when integrating more VRE into the energy systems a more holistic energy system approach tends to result in lower overall system costs [6]. Previous studies have also found that when the different energy sectors become more interrelated, market re-design to facilitate VRE integration have to be understood across the different energy sectors, as the different energy markets will to a larger extend affect each other [7].

Previous research has shown that the district heating (DH) sector can have an important role to play in the future integration and balancing of RE, due to a combination of existing storage capacity and technological diversity [8]. Furthermore, despite decreasing costs, battery storage remains an expensive solution for long-term electricity storage compared to heat storage alternatives found in the DH sector [9]. The storage potential in DH is especially relevant because of power to heat (P2H) technologies enabling the conversion of electricity to heat, typically based on conventional heating resistors, electrode boilers, or HPs. A transition towards P2H technologies, such as electric boilers (EBs) and electric heat pumps (HPs) in DH, coupled with heat storage could very well provide some of the critically needed flexibility and be an integral part of the future integration of VRE [10].

*Abbreviations:* COP, Coefficient of performance; DH, District heating; DSO, Distribution system operator; Dyn, Dynamic tariff; EB, Electric boiler; FRT, Flat-rate tariff; HP, Heat pump; NHPC, Net heat production cost; P2H, Power to heat; RE, Renewable energy; TOU, Time-of-use tariff; TSO, Transmission system operator; VRE, Variable renewable electricity.

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While both EBs and HPs enable the coupling of the heat and electricity sector and are useful technologies in integrating and utilizing VRE production, EBs and HPs provide vastly different benefits to the energy system [11]. HPs typically function as base-load units with many production hours due to high investment costs, low operation costs, and high efficiencies [12]. Therefore, HPs could prove to be an unreliable source of flexibility in the future, given the current operation mechanisms, where HPs only to a limited extent react to price signals from the day-ahead spot market and fluctuations in VRE production [12]. EBs are almost the exact opposite technology of HPs, providing a lower investment cost, but also lower efficiency. Enabling greater system flexibility through flexible operation of both EBs and HPs could prove to be a pivotal challenge for future RE systems.

The use of P2H technologies as a future flexibility mechanism is an area of growing interest among both academics and grid operators. However, as argued by Skytte [13], significant barriers to the realization of the P2H potential are present, including the market development and the regulatory setup. Key issues in the Danish context have been the preference for biomass heat only boilers; a result of the tax exemption for biomass, and the existing grid tariff structure hindering P2H utilisation.

A redesign of electricity grid tariffs could prove to be a useful mechanism for encouraging flexible operation. In an investigation of policy incentives for flexible DH in the Baltic countries, Sneum et al. [14] argue how flexibility is mainly provided by market incentives and very little by energy policy, raising the question of whether the existing market incentives are sufficient mechanisms for ensuring that the increased demand for flexibility is met. This is a challenge that is further exacerbated due to the conflict of ecological and financial efficiency of P2H control strategies, and the current lack of financial incentives for flexible P2H operation [15].

Through Balmorel simulations of the Nordic countries, Sandberg et al. [16] have investigated the impact of altering the grid tariff structure and found that the use of electricity in DH was significantly influenced. Likewise, a study of the North European power market based on Balmorel simulations concluded that the value of VRE increases, as the installed P2H capacity increased. In a study of a representative Danish DH system, Bergaentzlé et al. [17] analysed the impact of alternative tariff schemes on the operation of P2H technologies; this is however limited to only include EBs due to the site-specific nature of HPs. Similarly, Kirkerud et al. [18] investigated how changes to the grid tariffs influenced the operation of an EB in a typical Norwegian DH plant.

Tariffs are regulated locally by the distribution system operators (DSOs) and nationally by the transmission system operator (TSO). Danish DH companies are subject to a distribution tariff to the local DSO, in addition to transmission- and system tariffs paid to the TSO. All three are in the form of fixed tariff rates, where the total tariff payment is a result of the volumetric electricity consumption. The tariffs are supposed to be balanced to a level equal to the cost of operating and maintaining the grid, with a stated purpose from the Danish Electricity Supply Act of being cost-reflective, fair, and non-discriminating [19]. Thus, in theory, tariff rates should be cost-reflective. There is however notably no mentioning of encouraging flexibility.

While traditionally electricity grid tariffs have been designed using a volumetric rate (EUR/kWh), independent of time and place of consumption, such fixed price structure may not be suitable for the on-going transition towards VRE and the ensuing changes to the electricity market. Reneses et al. [20] outline how the cost of supplying electricity is not static but instead varies according to both time of the day and location of consumption. In hours with excess renewable electricity, the marginal cost for supplying additional electricity on the distribution- and transmission grid is low. On the other hand, supplying electricity during peak load hours is expensive, both due to increased losses as a result of intensity and the expensive necessary investments in peak grid capacity [20]. Concerns like these cause Bergaentzlé et al. [17] to argue that traditional volumetric tariff distorts the price signals from tariffs as they do not properly reflect the marginal supply cost.

Perhaps a response to the challenges related to the traditional volumetric tariff schemes, three Danish DSOs Radius (part of Andel as of September 2020) [21], Cerius [22] and Konstant [23] have implemented an alternative tariff scheme within parts of their grid area for testing and demonstration purposes. While the specific tariff rates are slightly different for each DSO, the general structure applied is the same. In all three areas the tariffs have been changed to consist of three different price periods; low, high, and peak pricing. This, at least in theory, adds an element of time to electricity consumption, rewarding consumption outside of the typical peak demand hours. For all three DSOs a tariff reduction of 39%–42% is provided for consumption during low periods, no changes to the tariff rate during high periods, and a tariff increase of 42%–48% is added for consumption during peak periods.

As shown, while P2H flexibility and interactions with electricity grid tariffs already have seen some attention within research, significant gaps in this can be identified. One notable observation is the absence of studies on flexible operation of HPs in DH, whereas typically studies on P2H flexibility only investigate the potential for EBs. This may be a result of the site-specific nature of HPs, causing a need for case and site-specific investigations due to the need for a low-temperature energy source in connection to the HP, as opposed to either large-scale aggregated analysis or investigation of average cases. Furthermore, integration of VRE is only correlated to the changes in P2H operation as a result of tariff changes on a large-scale (e.g. for the North European power market [24]), but not on a local scale. The integration of VRE locally should however not be underestimated, where increased system flexibility may assist in reducing grid congestion and thus reduce grid expansion needs, in addition to supporting local renewable energy strategies due to a lower curtailment of VRE and improved integration.

### 1.1. Scope and case

This study investigates the challenge of system flexibility specifically in the context of Denmark, where approximately 64% of all households are supplied by DH [25] and 64% of the electricity demand is supplied from RE [26], thus making Denmark a prime candidate for investigations of P2H flexibility in DH. Furthermore, Denmark is committed to the transition to a 100% renewable energy (RE) system by 2050 [27]; a goal that requires a continued expansion of especially wind power production and thus an increased need for flexibility and VRE integration.

We hypothesise that a redesign of the existing rigid tariff scheme can incentivise flexible operation of P2H technologies, and thus result in increased integration of VRE as a result of increased P2H flexibility. Such a change should be understood not only in the context of the electricity market side but also consider the local heat market, as shown by the Smart Energy Markets concept [7], where we for this study thus consider the tariff structure as an important part of the energy market structure. While a redesign of the similarly rigid electricity tax structure could possibly also contribute to increased demand-side flexibility as investigated in Albertsen et al. [28], or flexible operation in DH as investigated in Østergaard and Andersen [29], the scope of this study is limited specifically to the electricity grid tariff schemes. Thus, this study sheds light on how a redesign of the existing electricity grid tariff schemes can increase the incentive for flexible operation of P2H technologies in the DH sector.

The study applies techno-economic modelling of a case DH plant with different P2H technologies installed, located in a region with large amounts of VRE production. The chosen case is Ringkøbing DH system, located in Ringkøbing-Skjern Municipality in Denmark. Ringkøbing DH is found relevant for investigating the effect of redesigned grid tariffs on flexibility in the local integration of VRE as Ringkøbing Municipality is in the process of developing a new energy strategy emphasising flexibility of the energy system and integration of the large amounts of locally produced VRE, thus following an increasing tendency among municipalities to actively engage in energy planning [30]. Ringkøbing DH has already installed EB capacity alongside a highly flexible and fast regulating hybrid natural gas and electricity HP, making the investigation of flexible P2H operation possible for both EB and HP. Also, Ringkøbing Municipality is home to the largest installed capacity of onshore wind turbines in Denmark, with electricity production in 2018 amounting to 178% of the electricity demand within the municipality, making the challenge of integrating VRE to the local energy system highly relevant. Ringkøbing DH is modelled in detail to investigate the effect of new tariff designs on the operation and business economic viability of P2H technologies. The operation of P2H technologies is correlated to the local wind power production, to assess how changes to the tariff structure influence local integration of VRE.

While it is not possible to decide on complex policy design such as electricity grid tariffs based solely on individual case studies, the aim of this study is to feed into the discussion of policy implications and evaluating the effect of new grid tariff schemes both on the operation of a DH company, and in terms of VRE integration.

## 2. Methods

The study applies the tool EnergyPRO for modelling Ringkøbing DH system, the selected case site, and testing redesigned tariff schemes. Tariff schemes are evaluated based on a combination of technical and economic parameters. This section outlines the process of choosing a suitable tool for modelling Ringkøbing DH system, followed by a description of the established model and key assumptions and data. Finally, the analytical framework consisting of the parameters of which the results are analysed according to, is presented.

### *2.1. Simulation tool*

The purpose of this study's energy system analysis was to investigate the potential for increased flexible operation of P2H technologies and the influence of energy policy in the form of electricity tariffs. This was done by modelling and simulating the operation of Ringkøbing DH plant and testing how altering tariff schemes influence production and operation. For this analysis, a number of characteristics were necessary for the applied tool, including:

- Able to model DH at a local level including typical P2H technologies.
- Hourly calculation time steps.
- Possibility of including spot market and adhering both production and consumption accordingly.
- Able to simulate and optimize for a minimum of a one-year period.
- Possibility of including existing and potential future energy policy such as taxes and tariffs.

To simulate different system configurations and varying taxes and tariffs the software energyPRO [31] was used. energyPRO is mainly used for modelling and simulating local or site-specific energy systems such as a DH system. energyPRO is capable of optimising such systems operation according to existing conditions such as weather, fuel prices, taxes, and subsidies, and a variety of fossil fuel based-, renewable-, and storage technologies can be modelled. Furthermore, the possibility of simulating operation according to both existing and potential future market conditions makes energyPRO a relevant modelling tool for this specific study. energyPRO also has strong sector integration properties, highly relevant when investigating the potential for increased coupling of electricity and heating sectors. Finally, energyPRO is a proven and widely applied tool, utilized in many peer-reviewed studies, and is often the preferred choice for analyses focused on the DH sector. Examples of this include; modelling of scenarios for heat supply in a Danish municipality [32], an analysis on the use of booster HPs in combination with central HPs in DH [33] and simulations of DH systems in Finland with an increasing share of HPs [34].

The default optimisation principle of energyPRO, and the principle applied in this study, is to minimise operational expenditures, a result of a least-cost prioritisation strategy based on a priority list method. This is done by calculating a net heat production cost (NHPC), equal to the short-term marginal production costs for every production unit for every hour. The production unit with the lowest NHPC is activated first, followed by the second lowest if the demand (in this case heat demand) is still not fulfilled. As an alternative to this economic optimisation, it is possible to apply custom operation strategies. The energyPRO model in this study operates on a basis of perfect foresight, meaning that energyPRO is able to foresee electricity prices and demands for the entire optimisation period from the input time series. While this is a limitation of the tool and not entirely in accordance with real-life scenarios, it is not very different from practical operation where spot market prices are available 24 h before activating and heat demand and wind power production can be fairly accurately predicted due to forecasts.

This study applies hourly calculation steps for a one-year period (8,760 h) due to the coherence with the spot market data and other input data such as the electricity production from wind turbines and electricity consumption in Ringkøbing-Skjern Municipality. Since the purpose is to investigate the potential for flexible operation and the resulting integration of local wind power production, hourly calculation steps for a one year period is deemed sufficient.

### *2.2. Analytical framework*

Analyses of technical and economic nature are conducted with the purpose of clarifying how the operation of P2H technologies is altered based on the changing of tariff schemes. For this study, technical analyses primarily revolve around how the changes in operation patterns interact with the local wind power production, while economic analyses relate to the tariff income of the DSO and TSO, as well as the business economic impact for the DH company.

#### *2.2.1. Temporal operation of P2H technologies*

The change in operation and integration of wind power is analysed through hourly comparisons of the wind power production relative to electricity consumption. Naturally, it is preferable to have the P2H technologies operate during hours of excess electricity production from renewable sources, such as wind power. To test this, the production hours are divided into two categories; hours with excess electricity produced by wind power and production hours with a deficit of electricity produced by wind power. For every hour it is determined whether there is an excess or deficit of electricity produced from wind power relative to the electricity consumption of Ringkøbing-Skjern Municipality. It is possible to determine incurred changes in operation due to changes to the tariff schemes, and whether it is possible to incentivise increased production during hours with excess electricity production.

#### 2.2.2. Peak electricity production and export

The high wind power production of Ringkøbing-Skjern Municipality results in some hours with high peak power productions that must be exported, straining the grid. Grid expansions are expensive, so redesigned tariff schemes should preferably mitigate these peaks and reduce the export of electricity. To assess tariff schemes' influence on-peak hours, an assessment of how the most problematic peak hour is affected is included, in addition to an assessment of the 5% peak hours, and a total annual import-export balance.

#### 2.2.3. Business economy

To investigate how the business economy of the DH company is affected a heat production cost is calculated. The evaluated heat price is a marginal heat production cost, meaning that only the short-term operational expenses are included, i.e., O&M costs, fuel and electricity costs, taxes, and tariffs. Long-term expenses such as investment costs are not included since no new investments are included for this study and such long-term expenses do not generally influence the operation strategy of the system. The simple approach for the heat price calculation is seen in Equation (1).

$$\textit{Heat price} = \frac{\textit{Annual operation expenses}}{\textit{Annual heat demand excl. heat loss}} \tag{1}$$

Where.

| Heat price | [EUR/MWh] |
|---|---|
| Annual operation expenses | [EUR] |
| Annual heat demand excl. heat loss | [MWh] |

#### 2.2.4. Recovering grid costs

An overview of tariff expenses, paid by the DH plant based on the electricity consumption of the P2H technologies to the DSO and TSO is also included. The total tariff expense is relevant to consider since the DSO and TSO will need to recover the cost of maintaining the electricity grid, and any potential deficits must be recovered elsewhere through other payment mechanisms. As the tariff rates are supposed to be cost-reflective as mentioned in Section 1, the current total tariff payment can be considered as a form of break-even point.

### 2.3. System details

Ringkøbing DH plant is split into three locations; Ringkøbing plant, Rindum plant, and two solar heating fields located close to each other and to the Rindum plant. This has no influence on the energyPRO model, since in reality the heat distribution grid allows heat to be transported between the different sites. From Fig. 1 it can be seen that Ringkøbing DH plant includes various different technologies; natural gas boilers, a natural gas CHP engine, an EB, an air to water HP able to run on either natural gas or electricity, hot water storage tanks and solar heating. Furthermore, it can also be seen that natural gas, electricity and solar energy are the only energy sources used in the DH plant.

In the energyPRO model, all the different heating technologies can utilise all three hot water storage tanks, allowing the system to benefit from periods of low heat demand and low electricity prices due to high VRE production to store heat for later use. The model does not include any requirements on minimum or maximum yearly operation hours. This means that the system is free to supply the heat demand based on what combination of technologies is found to be cheapest, according to the hourly prioritisation principle in energyPRO and the technologies NHPC. Furthermore it is seen how the only electricity market included in the energyPRO model is the spot market which is connected to the P2H technologies and the CHP unit; further details on the assumed hourly electricity prices are included in Section 2.5. Finally, it can be seen that there is also an annual heat demand which must be met and an annual heat loss, due to heat loss in the DH pipes connecting the DH plant to the heat consumers.

### 2.4. Technical- and economic parameters

In Table 1 the installed technologies along with corresponding technical and economic parameters can be seen.

In Table 1 the O&M costs are classified as fixed and variable, where fixed O&M costs are annual costs independent of production, and variable O&M depend on the total production (i.e. utilisation of the technology). In addition to the O&M costs included in Table 1, further economic assumptions include the taxes, tariffs, and $CO_2$ quota costs; these can be seen in Appendix 1. Furthermore, the natural gas CHP plant produces electricity which is assumed to be sold at the spot market price (see Fig. 3). The revenue generated from the sale of electricity is subtracted from the annual operational expenditures.

The EB installed in Ringkøbing DH is of 12 MW capacity and is capable of regulating within a few seconds. The efficiency of EBs range from 98% to 100% [36] due to the losses being resistive, and therefore heat-producing as well. For the purpose of the modelling in this study, the efficiency is assumed to be 100%. One thing to note is that an EB converts a high-quality energy resource (electricity) to a low-quality energy resource (heat). This is important to keep in mind when considering the efficiency since compared to for example a HP, the efficiency is quite low. The EB is mainly used as a peak load unit during hours with very low electricity prices, the current flat-rate grid tariffs are therefore typically a significant part of the operational expenditures.

The HP installed in Ringkøbing DH plant is an air to water HP capable of being powered by either natural gas or electricity, depending on which energy source is cheaper. For this study, it is assumed that the HP can freely operate on either natural gas or electricity, depending on the current NHPC. Table 2 provides an overview of how the efficiency and heat production varies according to the ambient temperature for both the natural gas and electric operation mode for the HP assuming a forward temperature of 70 °C. The data in Table 2 is used to model the heat pump in energyPRO and ensure that the efficiency and production correlate to the ambient air temperature as specified by the manufacturer.

To model the HP in the energyPRO model, two production units are modelled, one powered by natural gas and the other powered by electricity. The operation of the two units is restricted to one unit at a time. Microsoft Excel is used to produce time series for the heat output and fuel consumption since these vary throughout the year depending on the ambient temperature due to the nature of it being an air to water HP. The data from Table 2 is used to construct these time series for every hour of the year using linear interpolation and the hourly ambient temperature data described in Section 2.5. The output, in the form of heat production, is a system output, meaning that energy consumption for defrosting and aircoolers is included, explaining why the heat production is higher at higher temperatures.

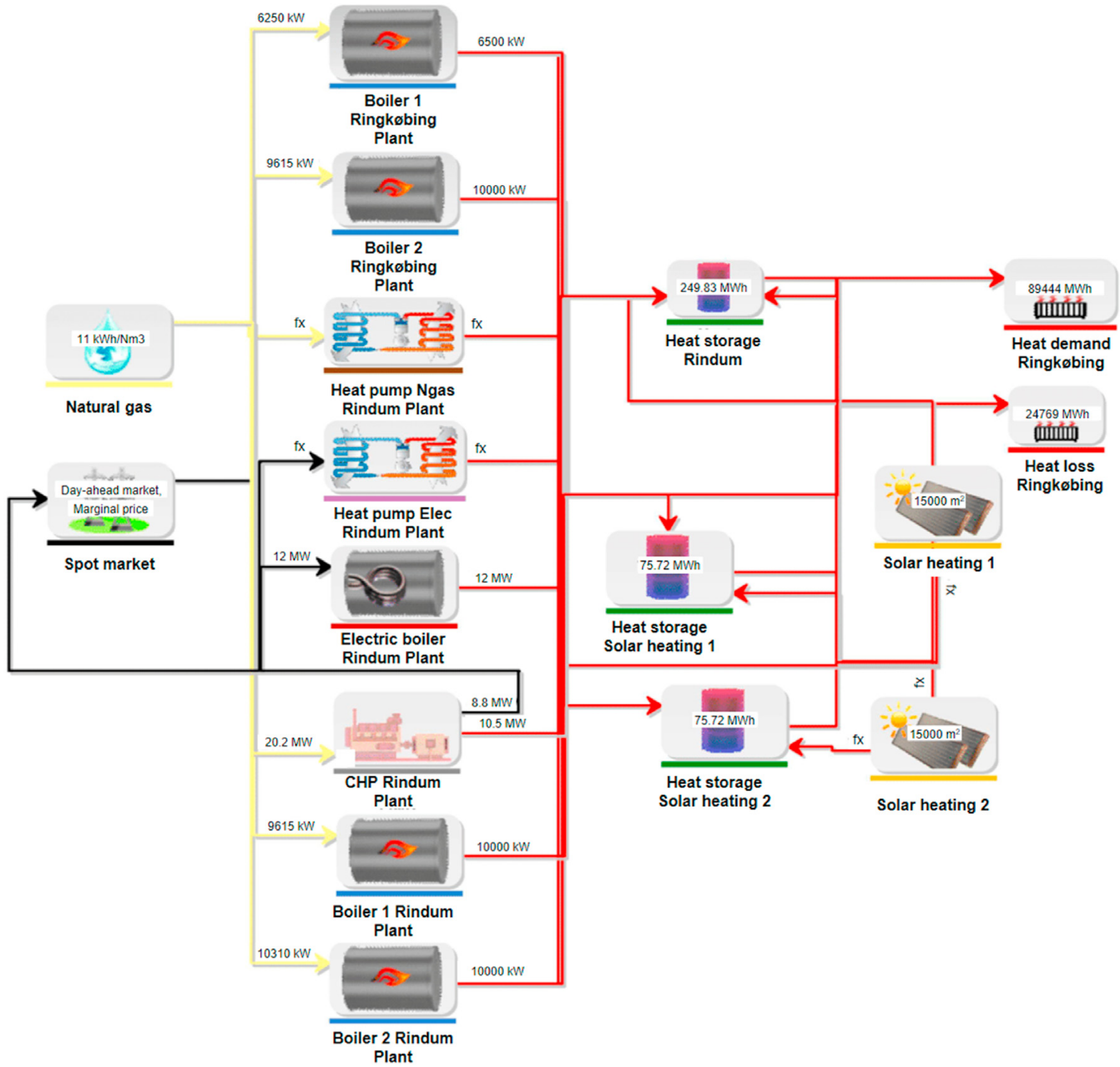


**Fig. 1.** Graphical overview of Ringkøbing DH plant as modelled in EnergyPRO.

**Table 1**
Key technical and economic parameters. Sizes and efficiencies are based on information from the DH plant. O&M costs are based on estimates from the Danish Energy Agency [36].

| Technology | Size | Efficiency | Fixed O&M | Variable O&M |
|---|---|---|---|---|
| *Natural gas boilers* | 36.5 MW | 102.25% | 2,000 EUR/MW/y | 1.10 EUR/MWh |
| *Natural gas CHP* | 10.5 $MW_{th}$ | $52\%_{th}$ and $43.6\%_{e}$ | 10,000 EUR/MW/y | 5.38 EUR/MWh |
| *HP: Natural gas operation* | 4.29 MW | 219% | 10,000 $EUR/MW_{e}/y$[a] | 7.99 EUR/MWh |
| *HP: Electricity operation* | 3.28 MW | 374% | 2,000 $EUR/MW_{th}/y$ | 3.29 EUR/MWh |
| *EB* | 12 MW | 100% | 1,100 EUR/MW/y | 0.80 EUR/MWh |
| *Solar heating* | 30,000 $m^2$ | [b] | – | – |
| *Heat storage* | 401.27 MWh | [c] | – | – |

[a] Based on axle power delivered to HP.
[b] Based on solar radiation, ambient temperature, and solar collector efficiency parameters [35].
[c] Based on top/bottom temperatures, height, insulation thickness, thermal conductivity, and ambient temperature [35].

## 2.5. Input time series

Critical input data to the model include the wind power production of the municipality, the electricity spot market prices, and the heat demand. All of these are included as 8,760 hourly values, thus enabling the temporal comparisons essential to the study of flexibility. How these are included will be elaborated in the following. The included time series are all from 2018 as this is the most recent year with complete data sets available for all the needed inputs, at the time of this study. Time series on external conditions (ambient temperature and solar radiation) are also included in the model, used to determine the hourly heat demand and heat production from the solar heating fields respectively. Both originate from the Design Reference Year data made by the Danish Meteorological Institute [38]; these will however not be described in further details within this study.

**Table 2**
Coefficient of performance (COP) and heat production for the HP when operating based on electricity and natural gas respectively [37].

| **Hybrid natural gas and electricity HP (electricity operation)** | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *COP* | 3.02 | 3.09 | 3.16 | 3.24 | 3.32 | 3.41 | 3.49 | 3.59 | 3.74 | 3.89 | 4.00 | 4.12 | 4.24 | 4.36 | 4.49 |
| *Production [MW]* | 1.85 | 1.99 | 2.14 | 2.29 | 2.47 | 2.63 | 2.80 | 2.99 | 3.28 | 3.58 | 3.79 | 4.01 | 4.24 | 4.47 | 4.47 |
| *Temperature [°C]* | −10 | −8 | −6 | −4 | −2 | 0 | 2 | 4 | 7 | 10 | 12 | 14 | 16 | 18 | 20 |
| **Hybrid natural gas and electricity HP (natural gas operation)** | | | | | | | | | | | | | | | |
| *COP* | 1.90 | 1.93 | 1.95 | 1.98 | 2.01 | 2.05 | 2.08 | 2.13 | 2.19 | 2.27 | 2.32 | 2.38 | 2.44 | 2.5 | 2.57 |
| *Production [MW]* | 2.60 | 2.77 | 2.96 | 3.15 | 3.34 | 3.54 | 3.75 | 3.96 | 4.29 | 4.63 | 4.87 | 5.11 | 5.36 | 5.61 | 5.6 |
| *Temperature [°C]* | −10 | −8 | −6 | −4 | −2 | 0 | 2 | 4 | 7 | 10 | 12 | 14 | 16 | 18 | 20 |

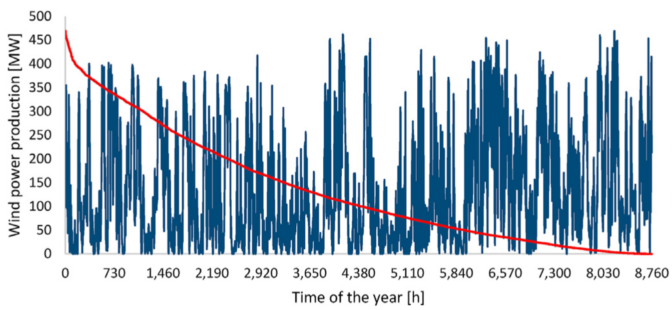


**Fig. 2.** Hourly wind power production in Ringkøbing-Skjern Municipality 2018. The red line is the corresponding duration curve. Data supplied by the Danish TSO Energinet. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

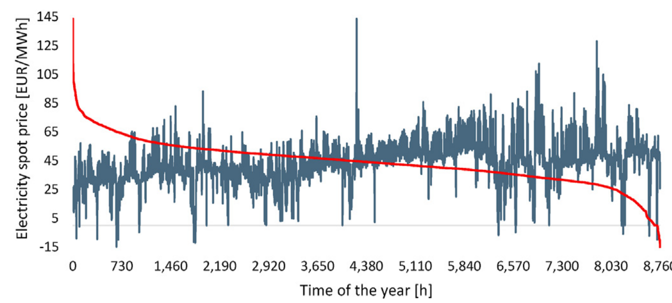


**Fig. 3.** Electricity spot market prices for Western Denmark (DK1) 2018; hourly values in blue and duration curve in red. Data available online [39]. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

### 2.5.1. Wind power production

From Fig. 2 it can be seen that the wind power production fluctuates throughout the year. The energyPRO model does not as such take into account the wind power production when simulating the system, which is based solely on a NHPC principle as described previously. Thus, to assess whether the changes to the grid tariffs result in increased utilisation of local wind energy, the hourly simulation output from energyPRO is compared to this wind power data in an Excel spreadsheet model.

### 2.5.2. Electricity spot market prices

The electricity spot market price seen in Fig. 3 is a critical input to the model because of the direct correlation to the NHPC and thus technology prioritisation. The average spot market price in 2018 was 43.9 EUR/MWh; higher than the average spot market price for 2000–2018 of 34.5 EUR/MWh, before adjusting for inflation.

### 2.5.3. Heat demand

The annual heat demand for Ringkøbing DH in 2018 was 89,444 MWh, excl. heat losses. This annual demand is distributed hourly using the degree-day method [35] based on the hourly ambient temperature, a temperature-dependent share of 70% for space heating, and a 30% temperature-independent share for hot water. It is assumed there is no demand for space heating during the summer months (June, July, August). The resulting time series can be seen in Fig. 4. In addition to the heat demand in Fig. 4, a heat loss of 27.7% is included in the model.

### 2.5.4. Electricity demand

The electricity demand shown in Fig. 5 is the demand of the entire municipality and is as such not needed for the energyPRO simulations of Ringkøbing DH plant. It is instead used to correlate the electricity consumption to the VRE production, and thus assess whether the changes to the grid tariffs enable increased local integration of VRE.

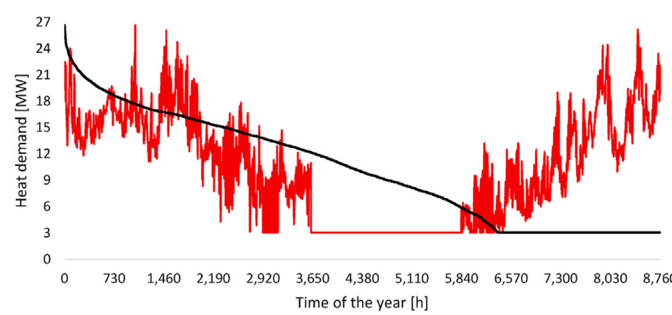


**Fig. 4.** Heat demand; hourly values and duration curve.

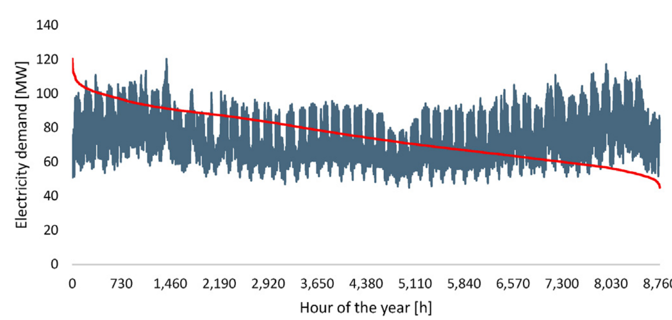


**Fig. 5.** Electricity demand for Ringkøbing-Skjern Municipality; hourly values and duration curve.

## 3. Investigated tariff schemes

This section presents the three tariff structures investigated (Table 3) and outlines how these could be a source of flexibility.

Re-designing tariff schemes will, almost inevitably, result in discussions on whether electricity grid tariffs are suitable as a flexibility enhancing mechanism, or whether e.g. market-based incentives should have this role. While this is an important and relevant discussion, this study assumes that the role and purpose of electricity grid tariffs can be extended to include grid flexibility and that they can thus be designed accordingly.

### 3.1. Flat rate tariff

For the flat-rate tariff structure (FRT), the tariff structure does not as such change from the existing tariff structure; payment is still dependent on the total electricity consumption without considering the time of consumption. A decrease in tariff payment would, however, lower the threshold for when the operation of EBs/HPs is feasible and could thus increase P2H utilisation. It can be argued that since neither electric HPs nor EBs are critical heat production units in the Danish energy system, an agreement ensuring flexibility in which the DSO/TSO is allowed to disconnect at will could be made, with a lower tariff rate to compensate for this option. The Danish TSO is working towards implementing such a principle as evident from the public hearing announced by Energinet in December 2019 [40]. Operation of P2H units would become more feasible at low electricity prices, where the fixed tariffs currently make up a significant portion of the operational costs, thus potentially increasing VRE integration and energy system flexibility.

A flat tariff reduction of 40% is tested for transmission-, system- and distribution tariffs in the model (Table 4). A 40% reduction is chosen because this closely resembles the decrease in tariff rate for the low price period in DSO areas where time-varying tariff rates have been implemented already, as described in Section 1. A flat-rate reduction of 40% is, therefore, a way to test the extent to which flexibility could be obtained from a very straightforward change where the low tariff rate is simply applied to all hours.

### 3.2. Time-of-use tariff

Fixed time-of-use (TOU) tariffs are becoming popular to implement by the various DSOs, and as previously mentioned in Section 1, fixed TOU tariffs have already to some extent been implemented in Denmark by the DSOs Radius, Konstant, and Cerius. For this study, the applied TOU tariff scheme is developed based on the average spot price fluctuations in West Denmark in 2018. This results in an average daily profile with higher prices during the peak morning and afternoon periods, and lower prices during the night, which is reflected in the tariff structure through low-, high- and peak load tariff rates. A schematic of the tested TOU scheme can be seen in Fig. 6.

The distribution tariff rates are based on the tariff rates implemented by the DSO Radius where TOU tariff rates were implemented in 2018. There are no existing experiences with also changing the tariffs to the TSO, therefore for this study, it is assumed that the TSO tariffs will vary in a similar pattern. This is done by increasing and decreasing the tariff rates by 50% for the low load and peak load hours respectively since this closely resembles the level of fluctuations implemented in the distribution tariff.

**Table 4**
Tested flat tariff rates. 0% constitute the tariff rates for Ringkøbing DH company in 2019.

| | Transmission | System | Distribution | Sum |
|---|---|---|---|---|
| Reduction | [EUR/MWh] | [EUR/MWh] | [EUR/MWh] | [EUR/MWh] |
| *0%* | 5.9 | 4.8 | 5.2 | 15.9 |
| *40%* | 3.5 | 2.9 | 3.1 | 9.5 |

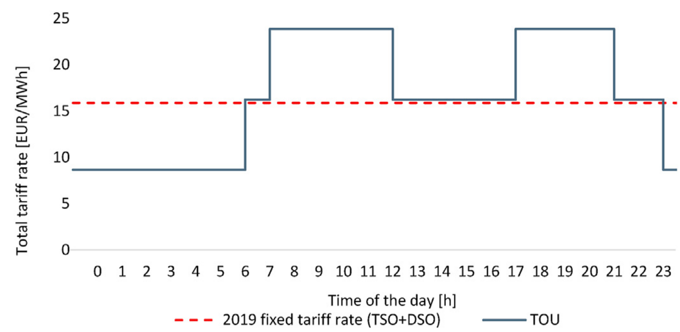


**Fig. 6.** TOU tariff scheme illustrated.

### 3.3. Dynamic tariff

Dynamic tariffs are, as opposed to fixed TOU tariffs, not based on a fixed time scheme. Such a structure could prove to be well-suited for future RE systems with uncertain VRE production and electricity prices. However, a dynamic tariff scheme is also significantly more complicated than a fixed TOU tariff scheme and relies on more sophisticated control mechanisms and automation on both consumption and production side. DH companies are generally familiar with adjusting their production according to price signals such as spot prices, which would make the introduction of dynamic tariffs easier here than in residential areas where knowledge, awareness, and ability to adjust electricity demand accordingly is likely lower.

In this study, dynamic tariff rates are generated as a function of the hourly spot price by calculating a percentage of the spot price, meaning that tariff rates will increase as the spot price increases and vice versa. This should, in theory, provide a greater incentive to utilise VRE since tariff rates are expected to be low during hours of high VRE production while aligning the price signals from spot prices and tariffs. This enables DH plants to place cost-reflective bids on the spot market. Such an approach would arguably also to a higher extent reflect the low marginal costs of supplying electricity when excess electricity is available and should reflect the high cost of supplying during peak load hours. In Fig. 7 the dynamic tariff scheme is illustrated through a duration curve, showing how the tariff rate varies depending on the hourly electricity price in 2018.

A spot price dependant tariff rate of 30% is chosen for this study. This is a combined total for all tariffs and is then separated into transmission-, system- and distribution tariffs based on the respective current share of each individual tariff. The tariff is designed so that the tariff rate cannot decrease below 0 EUR/MWh,

**Table 3**
Tariff schemes tested in simulations.

| *Tariff scheme* | *Abbreviation* | *Description* |
|---|---|---|
| Flat-rate-tariff | FRT | A flat volumetric tariff rate. Payment is based on the total electricity consumption. |
| Time-of-use tariffs | TOU | A fixed temporal time structure is applied, making electricity consumption more expensive during typical peak load hours. |
| Dynamic tariffs | Dyn | Tariff rates fluctuate dynamically on an hour-to-hour basis as a function of the spot market price. |

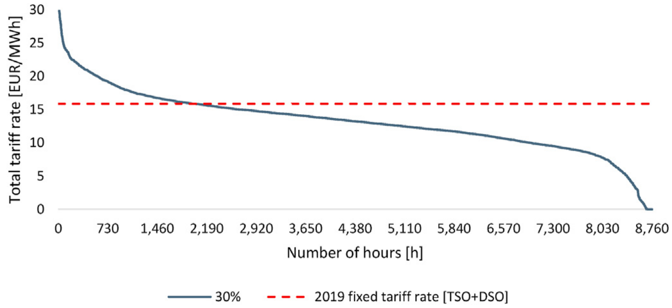


**Fig. 7.** Dynamic tariff scheme illustrated.

even if the spot price becomes negative. At a tariff rate of 30%, the tariff payment during hours of average electricity prices will resemble the reference tariff rates. The fluctuations will, however, be largely due to the nature of the electricity price dependency.

## 4. Results

The following section presents the results of the energyPRO model and the ensuing Excel data analysis, quantifying the effect of the investigated tariff schemes on the operation of the district heating plant.

### 4.1. Operation and integration of VRE

In Fig. 8 it can be seen that the utilisation of the P2H technologies varies depending on the applied tariff scheme. The highest utilisation is found for the Dyn tariff scheme, followed by the FRT tariff scheme. Especially the EB is utilized more in the Dyn tariff scheme compared to the Reference, FRT and TOU scenarios. This is a result of the low tariff rates during hours with low spot prices where EB operation is most relevant. However, depending on the individual perspective on flexibility and electricity consumption, this could be considered both a strength and a weakness of the Dyn tariff scheme.

As previously described, the wind power production in Ringkøbing-Skjern Municipality is at times very high, necessitating large grid capacity, at the expense of the DSO. Table 5 presents a comparison of how the different tariff schemes influence the peak excess wind production. This is a result of the difference between the wind power production and the electricity consumption of the municipality, combined with the consumption of the EB and the electric HP at Ringkøbing DH plant.

The TOU tariff scheme fails to decrease the maximum exported capacity compared to the Reference scenario (Table 5). The FRT tariff scheme and the Dyn tariff scheme is able to obtain a minor

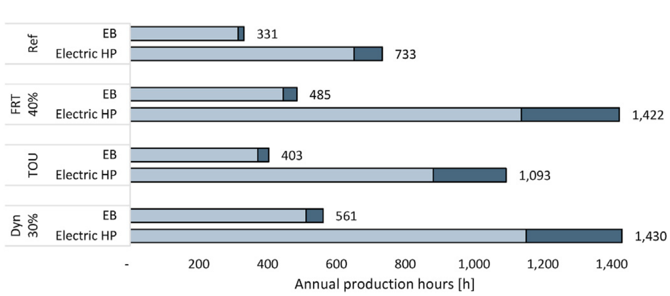


**Fig. 8.** Assessment of production hours and temporal distribution relative to local wind power production.

**Table 5**
Export of wind power relative to tariff scheme scenario.

| | Ref | FRT 40% | TOU | Dyn 30% |
|---|---|---|---|---|
| Max export [MW] | −386.0 | −385.2 | −386.0 | −384.5 |
| Export [MWh] | 513,810 | −2,418 | −1,140 | −3,349 |
| Top 5% export [MWh] | 136,761 | −330 | 62 | −374 |

reduction due to operation of the electric HP. The reason for this is that while the wind power production for the specific peak hour was very high, the spot price was not low enough to incentivise operation of the EB.

All three tariff schemes reduce the annual exported electricity, with the largest reduction coming from the Dyn tariff scheme, followed by the FRT tariff scheme, and finally the TOU tariff scheme with the smallest change. Looking at the hours where the top 5% of the electricity is being exported, the TOU tariff scheme actually increases the need for electricity export during the most critical hours, which is an undesired effect. This indicates that the fixed nature of the TOU structure does not always correspond to the fluctuations from the wind and electricity consumption.

### 4.2. Tariff expense

The total annual tariff expense varies for the different tariff schemes, however, most significantly for the EB. An interesting observation is that despite the FRT tariff scheme having the lowest average tariff cost throughout the year, the annual tariff payment for the EB is the highest, excluding the Reference scenario (Table 6). The explanation is that during the hours where the EB is actually in operation, the tariff is lower, which is especially true for the Dyn tariff scheme. The most radical change in the annual tariff expenses is for the Dyn tariff scheme, where the decrease in the annual tariff payment for the EB and for the electric HP is much lower than for the other tariff schemes and for the Reference scenario.

A reduced income for the TSO and DSO is potentially problematic for sustaining the electricity grid, therefore a redesigned tariff scheme may need to be supplemented with other financial mechanisms to recover the costs; e.g. a larger fixed payment component. A fixed component would not influence the short term marginal costs and the resulting operation of P2H technologies; the design of such a mechanism is however beyond the scope of this study.

### 4.3. Temporal distribution of production

From Fig. 9 and Fig. 10 it can be seen how the operation of both the electric HP and the EB varies throughout the day, prioritising times when the hourly spot prices are low; often during the night. In fact, all three redesigned tariff schemes increase the average production during the night for both the HP and EB. The TOU tariff scheme most substantially reduces the production during the morning and evening peak periods, indicating that the tariff scheme is working as intended with regards to incentivising operation outside of these periods.

**Table 6**
Heat production cost and annual tariff expenses for EB and HP.

| | Ref | FRT 40% | TOU | Dyn 30% |
|---|---|---|---|---|
| Heat production cost [EUR/MWh] | 55 | 54.8 | 54.9 | 54.5 |
| Tariff expense (HP) [EUR/year] | 10,171 | 11,729 | 10,159 | 8,027 |
| Tariff expense (EB) [EUR/year] | 62,933 | 55,210 | 51,269 | 24,759 |

Note: Heat production costs shown are short-term marginal heat production costs.

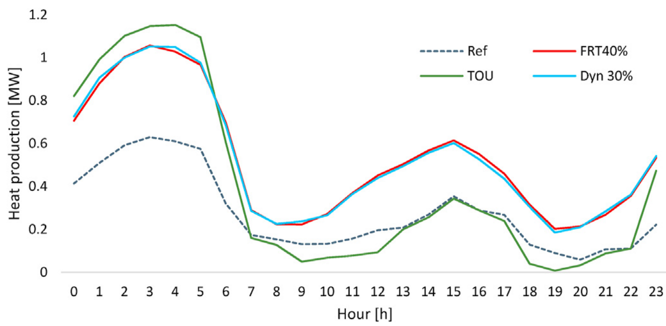


**Fig. 9.** Daily average production profile (heat pump).

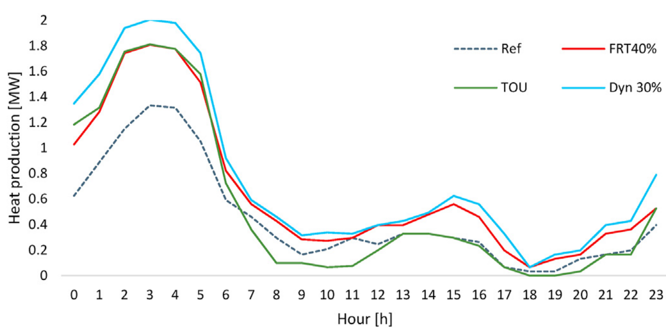


**Fig. 10.** Daily average production profile (electric boiler).

### *4.4. Excluding the hybrid natural gas HP*

To evaluate how the system operates with a traditional electrical HP, the natural gas component is removed from the model, since this more closely resembles traditional DH plants with electrical HPs.

Removing the natural gas component of the HP takes away a significant portion of the annual production, in addition to removing a low-cost alternative to operation during hours of high electricity prices. This removes most of the flexibility of the electrical HP, since now the electrical HP will have the lowest NHPC almost regardless of electricity price and tariff rate, and the price incentives obtained from the tariff schemes are no longer sufficient mechanisms to incentivise flexible operation, resulting in a large number of operating hours for the electrical HP (Table 7).

There are no significant changes to the operation of the EB apart from minor changes to the total annual production hours, ranging from a 1-h decrease to an 18-h increase depending on the tariff scheme. This is mostly because the EB rarely directly competes with the HP regardless of whether it is running on natural gas or electricity. Instead, the EB primarily competes with the natural gas boilers as a peak load unit, and thus removing the natural gas HP does not influence operation significantly. As a result of the combined changes to the operation of the EB and electrical HP, the P2H share increases by 18–23%.

The electrical HP operates very differently in a system without a natural gas HP. In all the tested tariff schemes for this sensitivity analysis, the electric HPs annual production hours increase by 6,954 - 7,651 h, depending on the scheme. This results in the electric HP having more than 8,380 annual production hours for each scheme in the sensitivity analysis. A further observation is that due to the increase in production hours across the different tariff schemes, the resulting annual production hours for the electric HP is almost exactly equal for all the tested tariff schemes. This indicates that the tariff scheme does not influence the decision of whether or not to operate the electrical HP, and the tariff schemes do not appear to incentivise flexible operation of the HP in a system where the electrical HP operates as a base-load production unit.

## 5. Discussion and conclusion

The results of this study indicate that increasing P2H flexibility is feasible within a DH setting through the use of redesigned tariff schemes, resulting in increased P2H utilisation and local integration of VRE. In a techno-economic analysis three different tariff schemes are tested; a flat-rate tariff scheme, a fixed time-of-use tariff scheme, and a dynamic tariff scheme with hourly variations. Based on energy system modelling, the influence of these three tariff schemes on the operation of P2H technologies is tested for Ringkøbing DH plant in Denmark. Below key findings from the techno-economic analysis for the three tested tariff schemes can be seen.

### *5.1. Flat-rate tariff scheme*

- Increases annual production hours by 47% for the EB, while decreasing the annual tariff expense by 12%.
- Increases annual production hours by 94% for the electric HP, while increasing the annual tariff expense by 15%.

### *5.2. Time of use tariff scheme*

- Increases annual production hours by 22% for the EB, while decreasing the annual tariff expense by 19%.
- Increases annual production hours by 49% for the electric HP, while decreasing the annual tariff expense by 0.1%.

**Table 7**
Comparison of model results where the natural gas HP part is excluded.

| | Original model | | | | | Without natural gas HP | | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Ref* | *FRT 100%* | *FRT 40%* | *TOU* | *Dyn 30%* | *Ref* | *FRT 40%* | *TOU* | *Dyn 30%* |
| *EB: Annual production hours [h]* | 331 | 1,376 | 485 | 403 | 562 | 7 | 13 | 17 | 17 |
| *- Excess electricity [h]* | 314 | 1,109 | 445 | 371 | 512 | 7 | 11 | 18 | 13 |
| *- Deficit electricity [h]* | 17 | 267 | 40 | 32 | 49 | – | 2 | −1 | 4 |
| *HP: Annual production hours [h]* | 733 | 3,746 | 1,422 | 1,093 | 1,430 | 7,651 | 6,966 | 7,294 | 6,954 |
| *- Excess electricity [h]* | 651 | 2,596 | 1,137 | 881 | 1,151 | 4,413 | 3,929 | 4,170 | 3,912 |
| *- Deficit electricity [h]* | 82 | 1,150 | 285 | 212 | 279 | 3,238 | 3,037 | 3,123 | 3,041 |
| *P2H share [%]* | 6 | 25 | 9 | 7 | 13 | 23 | 21 | 22 | 18 |
| *EB: Tariff expense [EUR/year]* | 62,933 | 0 | 55,210 | 51,269 | 24,759 | 1,242 | 1,520 | 2,142 | 1,111 |
| *HP: Tariff expense [EUR/year]* | 10,171 | 0 | 11,729 | 10,159 | 8,027 | 107,127 | 58,716 | 113,279 | 88,580 |
| *Heat price [EUR/MWh]* | 55.0 | 54.2 | 54.8 | 54.9 | 54.4 | 24 | 19 | 24 | 22 |

Note: Results for the analysis without natural gas HP are shown as the changes relative to the results of the original model.

*5.3. Dynamic tariff scheme*

- Increases annual production hours by 69% for the EB, while decreasing the annual tariff expense by 61%.
- Increases annual production hours by 95% for the electric HP, while decreasing the annual tariff expense by 21%.

The dynamic tariff scheme resulted in the most significant increase in production hours, alongside significant decreases in tariff income for the DSO/TSO. This effect will have to be negated elsewhere to recover sufficient income to maintain the electricity grid. As an immediate alternative to very complex tariff schemes, a reduced flat-rate tariff of 40% resulted in a very similar level of operation hours and flexibility provided by the EB. The effect of fixed TOU tariffs proved to be more limited on both P2H operation and tariff income to the DSO/TSO. It could, however, function as a suitable first step in the transition towards flexible tariff schemes due to ease of implementation and low-risk change to grid operators. The potential for flexible operation of the electrical HP relies on the presence of the hybrid natural gas HP as a low-cost alternative, since without it the price signal provided by electricity grid tariffs proved to be insufficient to influence the operation of the electric HP. There are therefore no clear flexibility benefits to reducing the tariff rate for HPs in such a situation since flexible behaviour cannot be expected, and it would likely be more relevant to move towards technology-specific tariff schemes.

This study has only investigated tariff changes in the context of a DH plant, but other consumers, both large- and small-scale e.g. industries or private households, likely have very different consumption patterns. Therefore, the results of this study are likely unable to be transferred directly to other electricity consumers, where additional adaptations could be necessary to achieve the desired changes. All three tariff schemes investigated in this study (flat-rate, TOU, dynamic), could be further differentiated in the future if needed. Such differentiations could include differences in tariff rates for different technologies, consumer types, locations, or local grid congestion levels. As an example, areas primarily with vacation houses (or otherwise seasonal demands) may require one scheme, while areas with solely permanent housing would require a different scheme. TOU tariff schemes could become increasingly complex following some of the previously mentioned differentiation possibilities, which could perhaps to some extent increase the correlation between VRE production and electricity consumption. However, the nature of TOU schemes and the fixed structure will inevitably limit the potential for flexibility as electricity demand, VRE production, and thus grid strains, become increasingly difficult to predict. Peaks are expected to occur as the wind blows, and accounting for this with a system based on either a fixed tariff or a predetermined scheme will be difficult.

The dynamic tariff scheme considered for this study is based on the electricity spot price, a simple approach, which DH companies would likely find relatively simple to implement. A challenge with such a scheme is how adjustments in the average price from one year to another would be determine, e.g., if the average spot price increases or decreases significantly from one year to another, should the dynamic tariff rate also increase or decrease? And how would this work in a real-life scenario, since for this study, the spot prices for the entire year are known in advance and an appropriate tariff rate can be designed accordingly. However, choosing a correct tariff rate will be more challenging without the luxury of perfect foresight of the spot prices for a whole year.

Future research should be pursued with regards to how technologies, industries and sectors beyond the DH sector are expected to respond to changes to the electricity grid tariff scheme. System-wide analysis and modelling, optimally encompassing a multitude of energy sectors, should also be conducted in addition to case-oriented methodologies such as the approach applied in this study. Future discussions on tariff schemes should aim to clarify the role of electricity grid tariffs in energy systems, and the extent to which flexibility should be incorporated as a desirable mechanism.

**Table 8**
Overview of assumed operating expenditures.

| Operating expenditures | | |
|---|---|---|
| Fuel costs | | |
| *Natural gas* | 0.27 | EUR/Nm$^3$ |
| ***Taxes and tariffs*** | | |
| ***Natural gas boilers*** | | |
| *Energy tax* | 22.31 | EUR/MWh |
| *$CO_2$ tax* | 6.65 | EUR/MWh |
| *NOx tax* | 0.00 | EUR/Nm$^3$ |
| ***Natural gas CHP*** | | |
| *Energy tax (Heat production only)* | 0.29 | EUR/Nm$^3$ |
| *$CO_2$ tax (Heat production only)* | 0.05 | EUR/Nm$^3$ |
| *NOx tax* | 0.00 | EUR/Nm$^3$ |
| *Methane tax* | 0.01 | EUR/Nm$^3$ |
| *Feed-in tariff* | 0.40 | EUR/MWh |
| ***Electric boiler*** | | |
| *Electricity tax* | 28.92 | EUR/MWh |
| *Transmission tariff* | 5.89 | EUR/MWh |
| *System tariff* | 4.82 | EUR/MWh |
| *Distribution tariff* | 5.17 | EUR/MWh |
| ***Heat pump (electricity)*** | | |
| *Electricity tax* | 34.67 | EUR/MWh |
| *Transmission tariff* | 5.89 | EUR/MWh |
| *System tariff* | 4.82 | EUR/MWh |
| *Distribution tariff* | 5.17 | EUR/MWh |
| ***Heat pump (natural gas)*** | | |
| *Energy tax* | 0.29 | EUR/Nm$^3$ |
| *$CO_2$ tax* | 0.05 | EUR/Nm$^3$ |
| *NOx tax* | 0.00 | EUR/Nm$^3$ |
| ***Natural gas costs (all units)*** | | |
| *Transmission costs* | 0.04 | EUR/Nm$^3$ |
| *$CO_2$ quotas* | 26.77 | EUR/ton $CO_2$ |

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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.

**Appendix 1. Operating expenditures**

Table 8 outlines operating expenditures for the technologies included in the energyPRO model. This does not include fixed and variable O&M costs as these were included in Table 1 in Section 2.4.

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