Beyond Biomass: Assessing Heat Pump and Hybrid Based Alternatives for Decarbonising District Energy Systems

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Abstract:

In its decarbonization strategy, the European Commission relies on biomass to reduce emissions in sectors such as heating and transport. In 2021, biomass accounted for 59 % of renewable energy consumption in the EU. However, its large-scale use raises two major concerns. First, the claimed CO_2 savings may translate into a carbon debt, which is incompatible with the urgency of climate mitigation. Second, sustainably available biomass resources are limited, potentially leading to a gap between increasing demand and constrained supply. Additional concerns related to biodiversity preservation can also be raised. In this context, some countries, such as the Netherlands, advocate for strengthening sustainability criteria and limiting biomass use to high-value end-uses, such as advanced biofuels, and only after higher-priority cascading uses.

Against this background, this work explores alternative solutions to biomass for the heating of a university campus supplied by a district heating network, based on hybrid systems combining air-to-water and geothermal heat pumps. Using a multi-energy optimization model for district energy planning developed by our team, we assess the impact of biomass price, photovoltaic deployment, thermal storage and battery installation on the optimal system configuration. Key indicators, including system cost, self-consumption and biomass savings, are analysed in order to formulate policy-relevant and operational recommendations.

Keywords:

Energy system, multi-energy, hybrid system, case-study, optimization, biomass.

1. Introduction

Biomass demand is forecast to increase substantially in the coming years, driven by favourable policies such as GHG accounting rules, which make biomass products a cornerstone of the EU decarbonization pathway. In the EU, the use of biomass is split between material and energy applications, accounting for 40 % and 60 % respectively in 2021, while bioenergy represented around 55 % of renewable energy consumption in 2019. By 2050, biomass use is forecast to increase by 70 % in the most conservative scenarios, and by up to 150 % in the more ambitious ones.

However, the amount of sustainably available biomass on the continent is severely limited, with few prospects for importing these resources from third countries without raising significant sustainability concerns. As a consequence, a gap of 40 to 100 % between biomass demand and supply is forecast by 2050. Addressing this gap is of utmost importance, as failure to do so would risk high levels of scarcity, elevated prices, and stranded assets. For these reasons, and due to the emergence of more competitive energy vectors (and related technologies) such as electricity, hydrogen, ammonia, etc., the future use of biomass is expected to concentrate on high-value material applications such as chemicals, wood products, and fibres, as well as high-value energy uses such as in aviation and industrial heat ([1, 2]). Meanwhile, traditional uses in low-temperature heat and power generation are expected to become increasingly uncompetitive. As stated in the 2021 Material Economics study ([1]): ”low-value uses carry the risk not only of expensive future adjustments, but also of stranded assets. The rapid pace of technological change makes any bet against current trends very risky.”

As an example of this re-evaluation of biomass use within the EU economic system, the Dutch government acknowledged that biomass could become scarce worldwide by 2030 and shifted its biomass policy towards a cascading use approach, prioritizing material applications such as construction, textiles, and bioplastics, and only using biomass as a fuel at a later stage ([3]). As an initial measure, the government decided to cut biomass subsidies for low-temperature generation and urged the EU to review its biomass policies and strengthen sustainability criteria ([4]).

Moreover, the zero CO_2 accounting rule for biomass is also under scrutiny. In addition to concerns regarding the sustainable management of biomass resources, the concept of carbon debt is gaining increasing attention. In a sustainably managed forest, carbon debt refers to the temporary excess of greenhouse gas emissions resulting from the combustion of biomaterials compared to a fossil fuel reference system. This effect arises from the immediate release of biogenic carbon during combustion and the delayed re-sequestration of that carbon through biomass regrowth. In other words, burning biomass can increase radiative forcing at a higher rate than fossil fuels for several decades before eventually reaching net-zero emissions ([5]).

In light of these considerations, this study explores alternative designs to biomass boilers for decarbonizing the energy consumption of a University campus. To that end, a multi-energy system optimization model is used to analyse the synergies between different technologies related to heat and electricity production and storage, with the objective of minimizing the total system cost. The specificity of the electricity billing structure is taken into account by considering a base load contract and a dynamic price for the remaining consumption, as well as a peak pricing mechanism. The analysis finally analyses the advantages and disatvantages of forming an energy community, allowing the different parts of the campus to share their electricity production and consumption, which is currently not the case.

2. Case-study description

The campus is composed of a wide variety of buildings, including educational facilities, offices, laboratories, residential buildings, sports facilities, and a hospital, among others. In addition, it includes a building dedicated to heat generation, which supplies a 10 km district heating network distributing heat to the different consumption centers.

The objective of this analysis is to explore practical system configurations and derive actionable insights regarding potential future developments. Due to constraints related to electricity billing structures and the granularity of available heating data, the buildings were grouped into 27 subdivisions, as presented in Figure 1. The heat and electricity demands of each building within a subdivision, as well as the roof area available for PV installations and the associated roof slope and orientation, were obtained and aggregated as follows:

- Demand profiles were obtained from the various databases available at ULiège for the year 2024, cleaned, normalized, and completed with data from 2023 where gaps were identified. The demand profiles were then aggregated by summing the demands of all buildings within each subdivision.

- Available roof areas for PV installation, along with their orientation and slope, were obtained using the Optim3D city model developed by the GeoScITY Lab at ULiège. Roof areas larger than 50 m^2 were summed for each building within a subdivision, and an area-weighted average was used to determine a representative roof orientation and tilt angle for each subdivision.

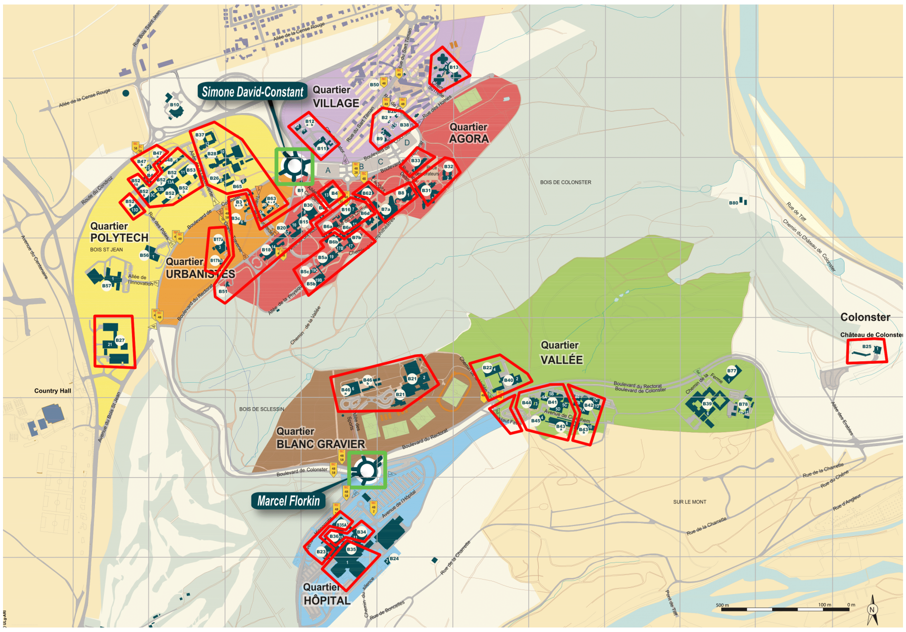
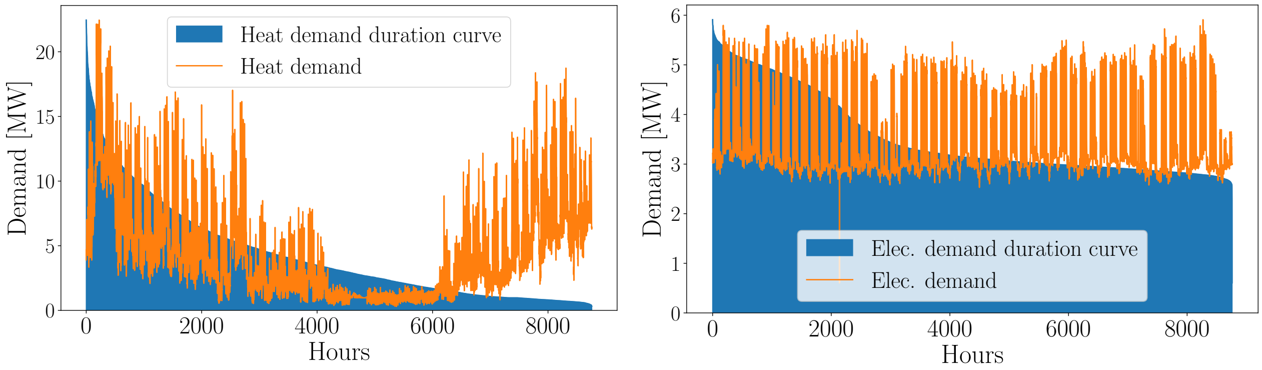


Figure 1: The campus and its constituent buildings, grouped into subdivisions.

The aggregated heat and electricity demand profiles, as well as their load duration curves, are presented in Figure 2, while the yearly consumption of each subdivision is shown in Figure 3. The graph shows that energy consumption is unevenly distributed among the subdivisions, and that heat demand is strongly concentrated in winter, autumn, and spring, with a low but relatively steady consumption during summer. Finally, the total roof areas available for PV installation are presented in Figure 4. The total yearly heat demand amounts to 37.894 GWh, with a peak load of 22.454 MW, while the yearly electricity consumption reaches 30.97 GWh, of which 70.7 % corresponds to base consumption. This base consumption is used as the contractual reference as explained in the next section. The peak load reaches 5.9 MW.



(a) Heat.

(b) Electricity.

Figure 2: Heat and electricity consumption of the campus throughout the year, and their related duration curves.

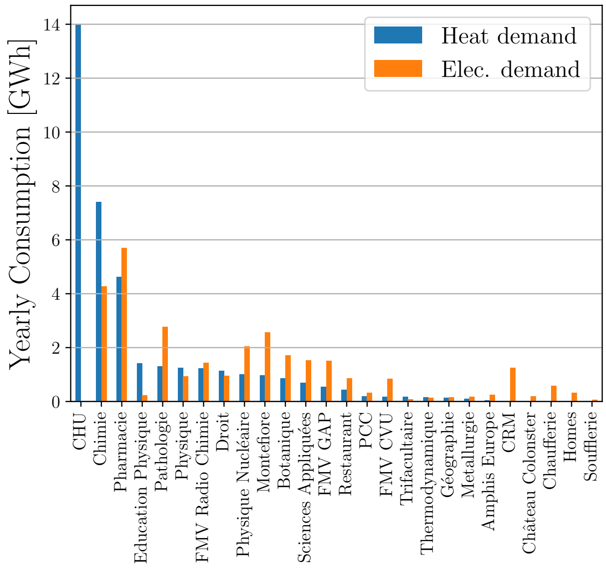


Figure 3: Heat and electricity consumption of the building subdivisions.

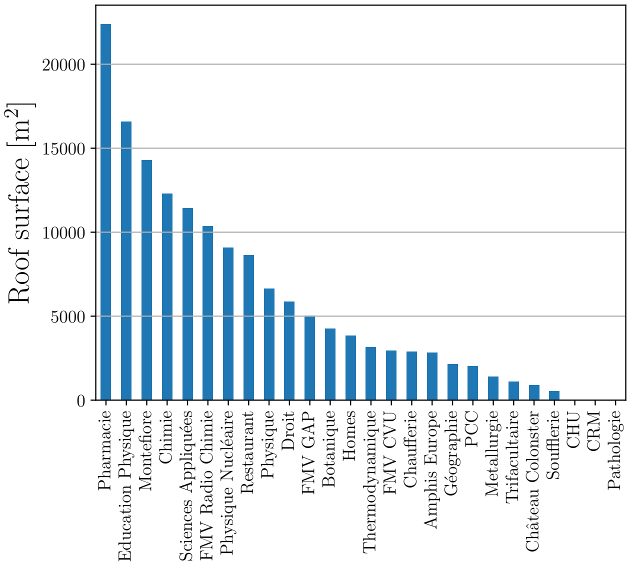


Figure 4: Total available roof surface for photovoltaic panels installation for the different building subdivisions.

3. Modelling assumptions and data

The reference price of wood pellets is fixed at 0.07 EUR/kWh, based on a price of 350 EUR/tonne, and a higher heating value of 5 kWh/kg.

The electricity retail price is composed of several components: a base consumption purchased at a ”clicked” price per MWh through a yearly contract, a variable consumption purchased at the day-ahead market price, a cost related to consumption peaks, and costs associated with transport, renewable contributions, charges, and special excises. A VAT of 21 % is applied to all components. The ”clicked” price used in the model is set to 0.218 EUR/kWh and includes energy price, transport costs, charges, and VAT. This value is based on the January 2025 electricity bill and applies to a base consumption of 2.5 MW, covering 70.7 % of the yearly electricity consumption. The remaining consumption is purchased at the 2024 day-ahead market price. Finally, the electricity peak pricing mechanism, which is normally based on monthly and yearly peaks, is simplified to a single yearly peak charged at 170 EUR/kW/year. This value corresponds to the ”2030 price”, for which the reduction factor on the effective peak no longer applies under current legislation. For electricity injection, the price is also based on the 2024 day-ahead market price. Under the current campus electricity tariff framework, each building subdivision must sell its electricity production surplus to the market, as electricity cannot be shared between subdivisions. In other words, electricity produced by PV installations in one subdivision cannot be used to cover the consumption of another subdivision, which must therefore purchase electricity from the market. In some scenarios, the possibility of forming an energy community is considered, allowing subdivisions to share electricity production and consumption and thereby reduce electricity exchanges with the market.

Heat network losses are modeled based on a 75–55 °C district heating network with a thermal loss coefficient of 3.86 W/(m K). This coefficient was evaluated using available 2024 heat consumption and generation data, as well as hot water and ambient air temperature date. Seasonal interruptions on parts of the network are taken into account in the network model.

Ambient air temperature and solar irradiation data are used to evaluate the heat pump coefficient of performance (COP) and PV production, respectively, and are obtained from the latest available PVGIS database for the year 2023.

The investment costs and lifetimes of the technologies considered in the different scenarios are provided in Table 1. The prices for PV installations and batteries are based on a recent project developed at the university. The heat pump investment cost is based on consultations with heat-pump manufacturer and corresponds to a conservative estimate within the communicated range of 500–800 EUR/kW. The price of the thermal storage tank is taken from an IEA technical report from the Fraunhofer Institute [6] and corresponds to a non-pressurized steel tank with a volume of 2 500 m^3. For a volume of 10 000 m^3, the unit cost decreases to 220 EUR/m^3; this value is used in the full heat pump scenario, which requires a significantly larger storage capacity. The tank diameter is also increased from 17 to 30 m in that scenario, as it has a significant impact on thermal losses. Finally, the biomass boiler investment cost is taken from the upper-bound 2020 estimates of the Danish Energy Agency for large wood-chip biomass boilers [7].

Regarding technology efficiencies, the Lorenz efficiency of the heat pump is set to 43 % to match the data provided by the manufacturer. The higher heating value efficiency of the biomass boiler is assumed to be 90 %, while the thermal loss coefficient of the heat storage is set to 1.3 W/(m^2 K).

Table 1: Investment cost and lifetime for the technologies considered in the design.

	Investment cost	Lifetime
Biomass boiler	450 euro/kWth	25 years
Heat pump	800 euro/kWth	25 years
PV	955 euro/kW	20 years
Battery	215 euro/kWh	10 years
Heat storage	300 euro/m^3	25 years

4. Results

In the following sections, results and analyses are presented for various system configurations. First, the reference case is presented, in which a single biomass boiler technology is used to cover the entire heat demand of the campus. Then, two scenarios are compared, in which all the available technologies can be used, but heat is produced entirely either with a biomass boiler in the first one or with a heat-pump in the second one. Next, a hybrid configuration, in which biomass a biomass boiler and a heat-pump complement each other, is investigated. Finally, scenarios investigating the advantages and disadvantages of forming an energy community in the context of increasing PV installation are presented.

4.1. Reference

In this reference case, a single biomass boiler technology is used to cover the entire heat demand of the campus energy district. No heat storage, batteries, or PV installations are included in the system design.

In this scenario, the total annualized system cost amounts to 12.23 MEUR, and the required installed biomass boiler capacity is 24.795 MW. This capacity is necessary to cover both peak heat demand and network losses. These losses represent 26.68 % of the total heat production, corresponding to 13.8 GWh, or 36.6 % of the heat demand. The total yearly heat production reaches 51.684 GWh, requiring 11.485 ktonnes of pellets per year at a cost of 4.019 MEUR/year. Regarding electricity, the average yearly retail price amounts to 0.247 EUR/kWh.

To reduce the required installed biomass boiler capacity, two options can be considered: increasing the network operating temperature to store heat directly in the network during low-demand periods, or installing a dedicated thermal storage tank. In the first case, network losses would increase, while in the second case, additional investment costs are incurred. For the latter option, a storage volume of 1 778.56 m^3 would be optimal, and would decrease the required boiler installed capacity to 18.459 MW. This configuration reduces the total annualized cost to 12.12 MEUR/year, at the cost of an increased installation and operation complexity. In this case, thermal losses associated with the storage amount to 73 MWh, or approximately 25 % of the yearly stored heat. A similar analysis should be conducted for the first option to enable a direct comparison of their economic performance.

4.2. Full heat pump vs. full boiler

Before considering hybrid system designs, two scenarios are compared: one in which heat demand is fully covered by a heat pump, and another in which it is fully covered by a biomass boiler. In both scenarios, electricity is assumed to be freely exchanged between buildings. The resulting system designs are presented in Figure 5.

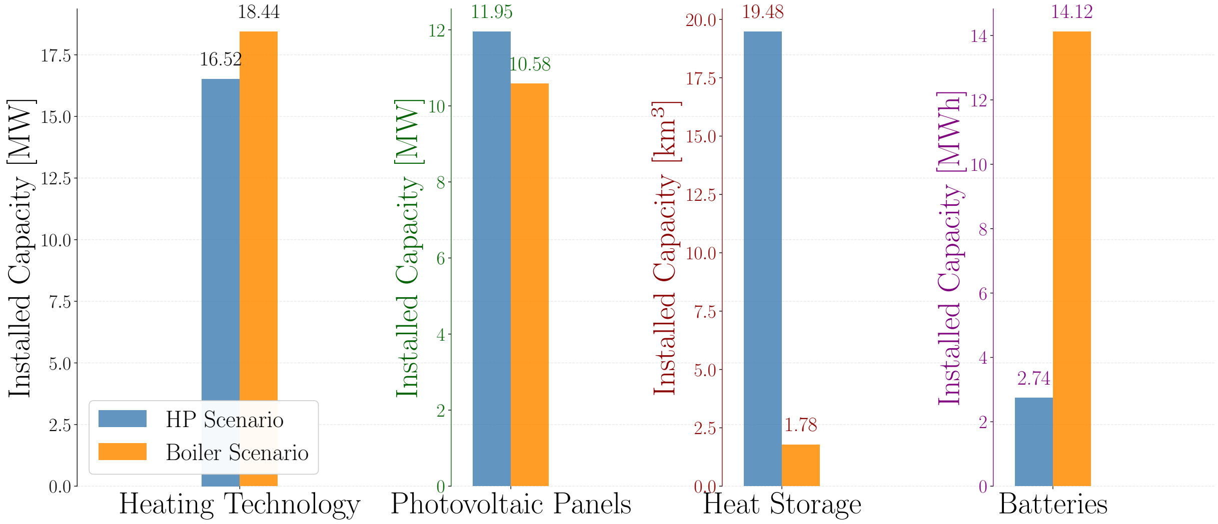


Figure 5: Comparison of the energy system design for the full boiler vs. full heat pump scenarios.

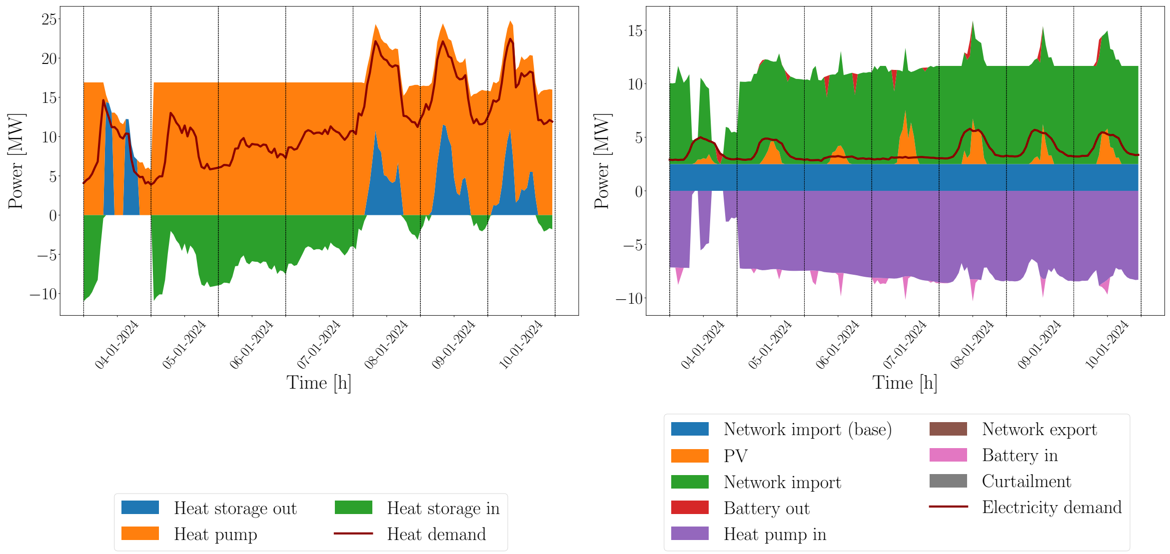
The total annualized system cost amounts to 11.37 MEUR for the biomass boiler scenario and 12.4 MEUR for the heat pump scenario, while the yearly biomass expenditure reaches 4.025 MEUR. When comparing to the reference case with thermal storage, we deduce that the reduction in system costs observed in the biomass boiler scenario is primarily driven by the installation of PV and battery storage. In the biomass boiler scenario, the maximum available PV capacity is not installed.

For the two scenarios to reach cost parity, the biomass price would need to increase by 25.6 %, from 0.07 to 0.088 EUR/kWh, corresponding to 439 EUR/tonne. While significant, such an increase has already been observed in other energy markets, such as natural gas, and remains plausible given the current biomass market outlook discussed in the introduction.

Electricity auto-consumption reaches 84 % in the heat pump scenario and 57 % in the biomass boiler scenario. This auto-consumption could be further increased by replacing the yearly base-consumption contract with shorter-duration contracts, as discussed in Section 4.5.. Regarding self-sufficiency, 20.8 % of total electricity consumption, including for heat services, is covered by local production in the heat pump scenario. In the biomass boiler scenario, 20.4 % of electricity demand is locally covered (24.6 GWh imported), while 100 % of pellet demand is imported (51.7 GWh or 11.5 ktonnes).

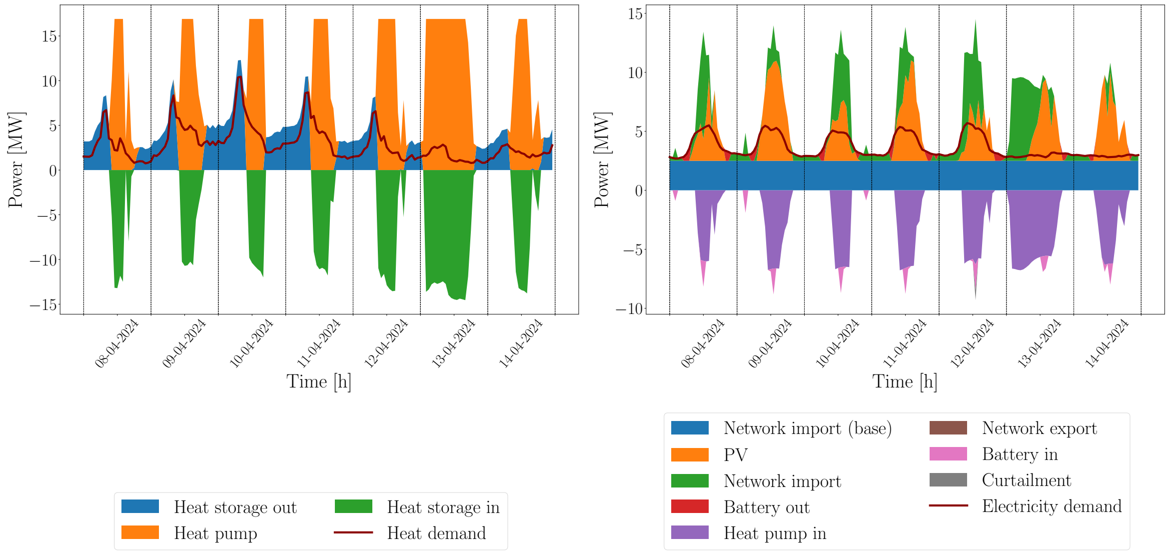
In the heat pump scenario, the system achieves a yearly average COP of 2.4, resulting from a large temperature lift in winter and a Lorenz efficiency of 0.43. This value corresponds to the average of the 2.2-2.6 COP range communicated by the heat-pump manufacturer for this configuration. Yearly thermal storage losses amount to 3.68 GWh, corresponding to a storage efficiency of 86 %.

The case in which no energy community is formed has been considered as well for both the full heat pump and full boiler scenarios. In the full heat pump scenario, the total annualized cost increases by 240 kEUR. Regarding the optimal design, the installed capacity of heat pump slightly decreases to reach 16 MW, the heat storage increases slightly to 20000 m^3, PV capacity decreases to 10.7 MW, while the battery capacity increases to 5.28 MW. In case no battery are installed in the subdivisions, the total annual cost difference would barely increase to 290 kEUR/year. The costs difference arise because without energy community, the heat pump can not absorb electricity production surplus from PV panels, which limits the quantity of panels that can be installed in a profitable way. In the full boiler scenario, the difference in total annualized cost between forming or not an energy community is 40 kEUR. This difference increases to 257 kEUR if no battery can be installed in the subdivisions. In the full boiler scenario, the system already relies on batteries to efficiently integrate PV production. This is why there is not much difference when forming or not an energy community and why this difference rises when no batteries can be installed inside the subdivisions.



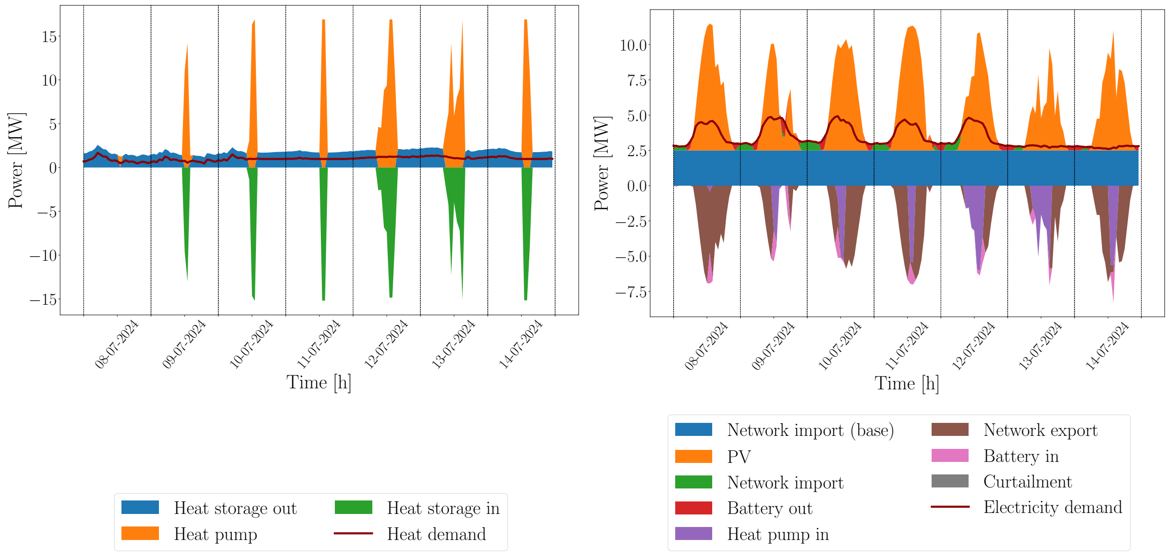
(a) Heat balance in winter.

(b) Electricity balance in winter.



(c) Heat balance in spring.

(d) Electricity balance in spring.



(e) Heat balance in summer.

(f) Electricity balance in summer.

Figure 7: System operation in the full HP scenario for different period of the year..

The operation of the heat system in the heat pump scenario for different periods of the year is illustrated in Figure 7. In winter, the system primarily imports electricity from the grid to power the heat pump. To operate effectively in practice, accurate consumption forecasts are essential to ensure sufficient heat storage is available in anticipation of high-demand periods. During the intermediate season, the heat pump operates mainly during daytime hours, when additional PV production is available and the day-ahead electricity price is low, covering demand and charging the storage, which is then discharged overnight. In summer, most electricity is sold to the market, and the heat pump operates at full capacity for a few hours during the day to charge the thermal storage.

4.3. Hybrid designs

A further cost reduction can be achieved by considering hybrid heat production systems combining a heat pump and a biomass boiler. Figure 9 explores different levels of ambition for local electricity production, as well as various biomass price scenarios. First, the installed PV capacity is observed to be independent of the biomass price and, consequently, of the installed heat pump capacity. This indicates that, across all explored scenarios, installing the maximum available PV capacity is always economically optimal.

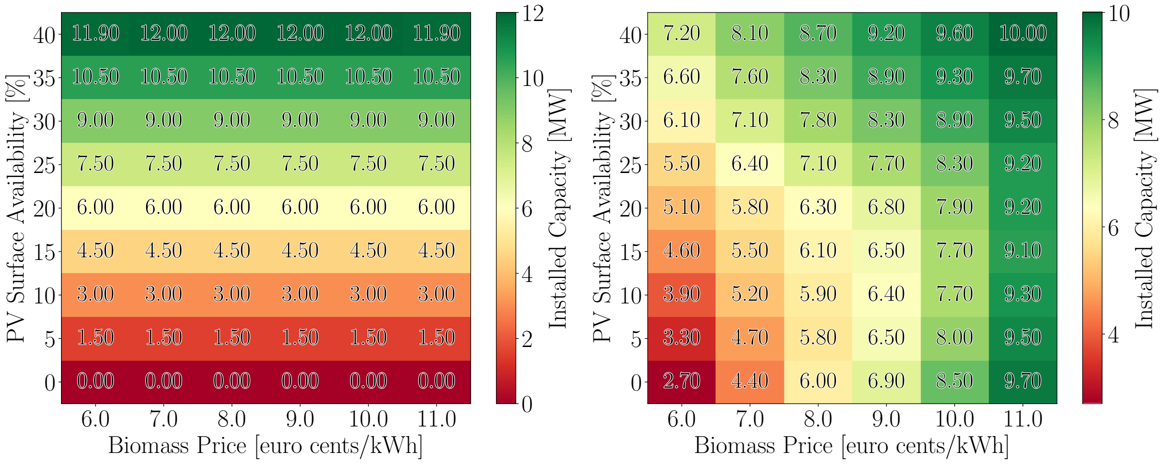
Regarding heat pump installation, we note that for lower biomass prices, the heat pump capacity depends strongly on the installed PV capacity, while this dependence becomes less pronounced at higher biomass prices. This is because, during summer and the intermediate seasons, heat pumps benefit both from a higher COP and from surplus electricity from PV panels (if the campus forms an energy community). For low biomass prices, the heat pump is only profitable when PV surplus is available - no PV, no heat pump. When biomass prices are higher, the heat pump becomes profitable in summer even without PV, thanks to the higher COP, which makes electricity from the grid competitive with biomass. In that case, installing additional PV does not lead to a large increase in heat pump capacity, although it does improve self-consumption and reduce costs. Instead, additional PV gradually makes the heat pump more competitive in the intermediate season, when solar availability is still significant and grid electricity is less competitive due to the lower COP.

The installed biomass boiler capacity primarily depends on the biomass price. At low biomass prices, heat pumps remain uncompetitive in winter, making it economically preferable to retain a large biomass boiler capacity to cover winter demand, even if it is underutilized in other seasons. As biomass prices increase, heat pumps become more competitive during winter, allowing the biomass boiler capacity to be reduced and limiting its operation to the coldest periods of the year.

When no PV is installed, batteries can be used to exploit electricity price fluctuations. However, as biomass prices increase and heat pumps become competitive, thermal storage coupled with heat pumps can replace batteries by shifting electricity consumption in time and storing energy as heat. With increasing PV capacity, battery deployment becomes more attractive to capture excess generation, although this need decreases as heat pump capacity increases.

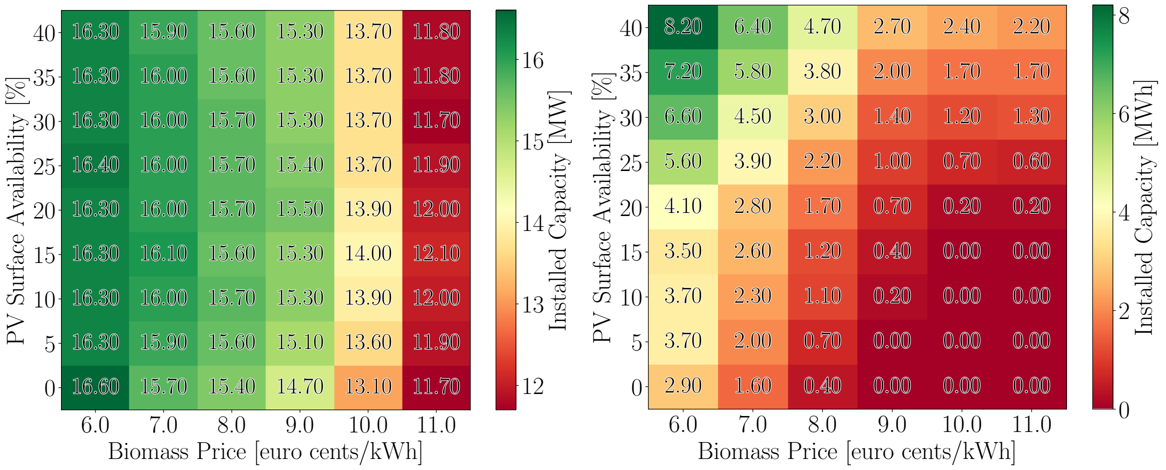
Regarding thermal storage, its required capacity increases with the growing use of heat pumps during intermediate and winter seasons. This trend also applies to the quantity of heat produced by heat pumps, which depends primarily on the biomass price once it exceeds 0.07 EUR/kWh. Below this threshold, the heat pump-to-biomass heat production ratio also depends on the installed PV capacity. A higher biomass price makes the heat pump more competitive in the intermediate seasons and in winter, which is where the heat consumption is concentrated. It therefore has a strong impact on the heat pump-to-boiler heat production ratio.

Allowing for a hybrid design significantly reduces the total annualized cost of the systems. To compare with the full boiler scenario of the previous section, the hybrid design related to the 40 % roof availability and a biomass price of 0.07 EUR/kWh has a 578 kEUR lower annualized cost. When considering a biomass price of 0.11 EUR/kWh, the difference between the full heat pump scenario – the cheapest scenario between both for this biomass price – and the hybrid scenario is 640 kEUR.



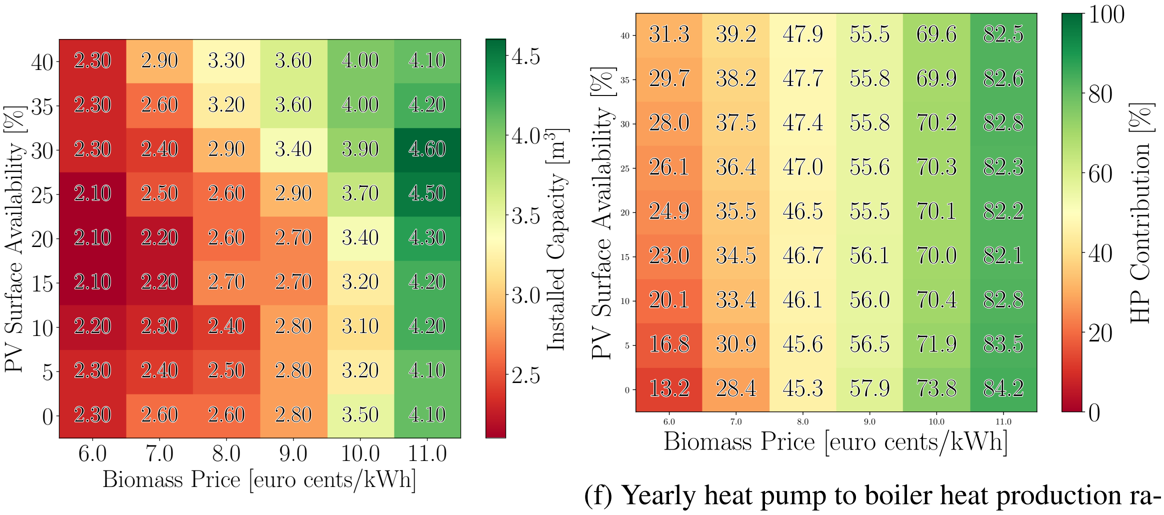
(a) Photovoltaic panels.

(b) Heat pump.



(c) Boimass boiler.

(d) Batteries.



PV Surface Availability [%]	6.0	7.0	8.0	9.0	10.0	11.0
40	2.30	2.90	3.30	3.60	4.00	4.10
35	2.30	2.60	3.20	3.60	4.00	4.20
30	2.30	2.40	2.90	3.40	3.90	4.60
25	2.10	2.50	2.60	2.90	3.70	4.50
20	2.10	2.20	2.60	2.70	3.40	4.30
15	2.10	2.20	2.70	2.70	3.20	4.20
10	2.20	2.30	2.40	2.80	3.10	4.20
5	2.30	2.40	2.50	2.80	3.20	4.10
0	2.30	2.60	2.60	2.80	3.50	4.10

(e) Hot water storage.

PV Surface Availability [%]	6.0	7.0	8.0	9.0	10.0	11.0
40	31.3	39.2	47.9	55.5	69.6	82.5
35	29.7	38.2	47.7	55.8	69.9	82.6
30	28.0	37.5	47.4	55.8	70.2	82.8
25	26.1	36.4	47.0	55.6	70.3	82.3
20	24.9	35.5	46.5	55.5	70.1	82.2
15	23.0	34.5	46.7	56.1	70.0	82.1
10	20.1	33.4	46.1	56.0	70.4	82.8
5	16.8	30.9	45.6	56.5	71.9	83.5
0	13.2	28.4	45.3	57.9	73.8	84.2

(f) Yearly heat pump to boiler heat production ratio.

Figure 9: Comparision of optimal hybrid energy system designs, considering different levels of ambition for PV installation and increasing biomass prices.

To summarize, the heat demand profile of the campus, with a low but steady consumption in summer and a significant demand already in the intermediate seasons, makes it profitable to install a heat pump in the vast majority of scenarios. This is due to the higher heat-pump COP in summer and the possibility of using surplus electricity from PV panels. However, the heat pump is less competitive in winter, and its competitiveness depends on the biomass price. The installed capacity of the biomass boiler remains significant and decreases as the heat pump becomes more competitive during winter. These results can be better understood and visualized by looking at Fig. 10.

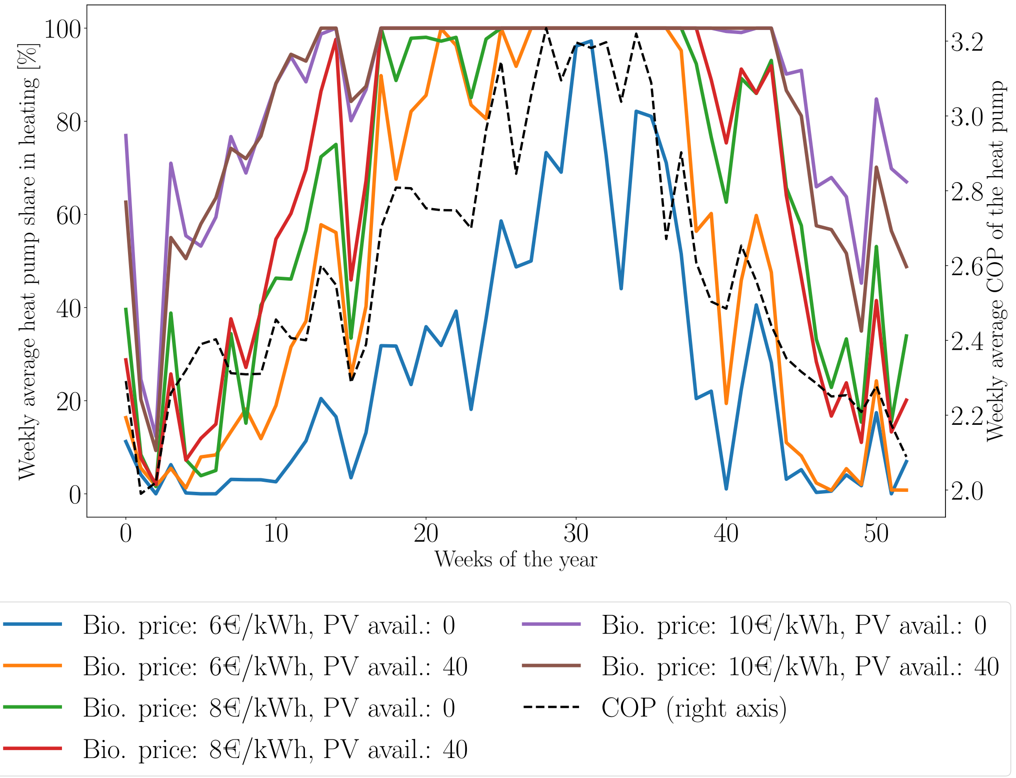


Figure 10: Weekly average heat pump to boiler heat production ratio throughout the year for different scenarios.

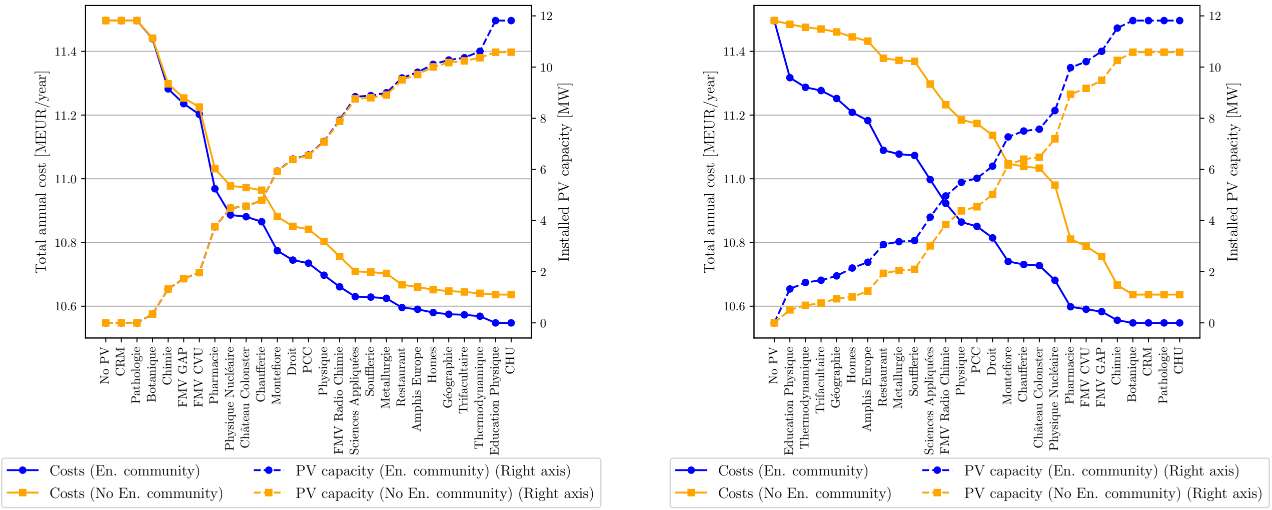
4.4. Energy community

Under the current electricity tariff framework, each building subdivision must sell its electricity production surplus to the market and purchase electricity from the market to cover its own demand. In this section, the impact of this tariff structure on the economic performance of PV installations is analyzed, along with the potential benefits of forming an energy community. An energy community would allow subdivisions to share electricity production and consumption, thereby increasing campus-wide auto-consumption.

This analysis is based on the observation that, in the absence of an energy community, economic value is lost whenever a subdivision generates surplus electricity. Two PV deployment strategies are therefore considered: in the first, subdivisions with high auto-consumption potential are equipped first; in the second, subdivisions with low auto-consumption potential are prioritized. In Figure 11a, PV installations are deployed from the highest to the lowest consumption-to-roof-area ratio, while in Figure 11b, deployment follows the opposite order. In both cases, the annualized system cost is compared for scenarios with and without an energy community as PV capacity increases. All scenarios assume a fixed heat pump capacity of 6 MW, no batteries, and a biomass price of 0.06 EUR/kWh.

Figure 11a shows that cost differences between the two configurations only start to appear beyond approximately 3 MW of installed PV and remain below 100 kEUR/year. In contrast, Figure 11b shows that cost differences arise immediately after the first PV installation and can reach up to 300 kEUR/year. In scenarios in which a heat pumps would not be installed, these cost differences would slightly be reduced. Also, investing in large capacities of batteries can also bring this difference down, as explained in the Section 4.2.

In summary, while not forming an energy community always yields lower profitability, an appropriate PV-battery deployment strategy can significantly reduce these losses by maximizing auto-consumption at the building level. However, when heat pumps are installed, allowing electricity sharing between subdivisions becomes essential to capture the PV surplus and integrate more PV capacity.



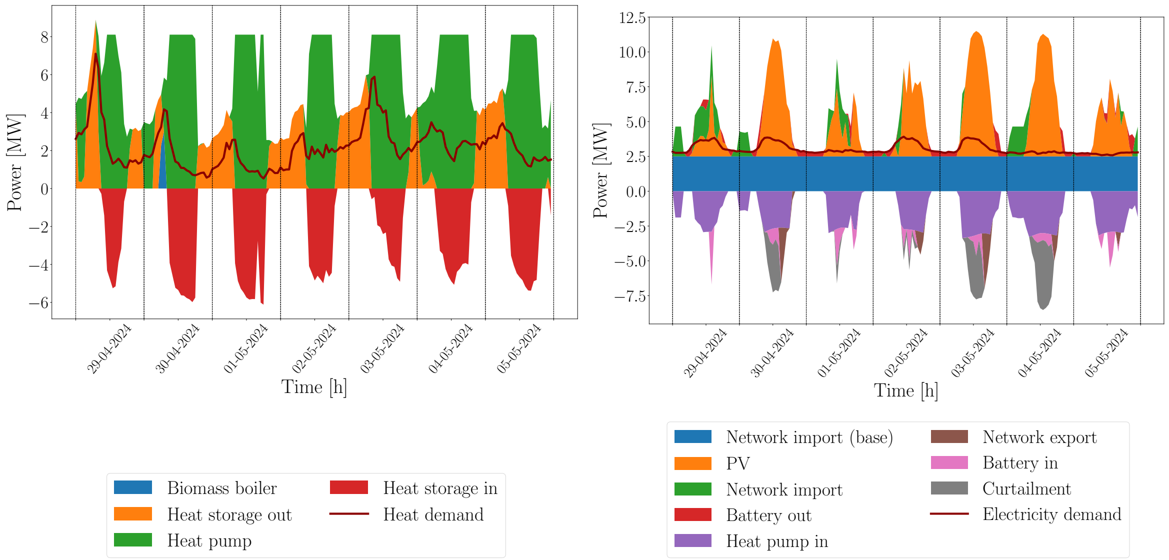
(a) Decreasing ratio.

(b) Increasing ratio.

Figure 11: Comparison of the annualized cost of the system with and without energy community, with increasing installed capacity of PV panels, with installation from the smallest to the highest consumption to roof area ratio (right), or in the opposite order (left).

4.5. Electricity tariff design

As more PV panels are installed on the campus, the number of hours during which electricity must be sold to the market while simultaneously importing electricity to cover the base consumption contract increases. In addition, many hours throughout the year feature negative electricity prices. As a result, electricity can be produced but cannot be fully consumed due to the base consumption contract, and cannot be sold on the market because of negative prices. This represents a loss of productivity for the PV system. In cases where PV installation increases significantly, it may be profitable to switch from a yearly base-consumption contract to shorter-period contracts to reduce the hours in which electricity cannot be auto-consumed and would otherwise be curtailed. These phenomena can be observed in Fig. 12.



(a) Heat balance.

(b) Electricity balance.

Figure 12: Operation of the system in spring, for a biomass price of 7 euro cent/kWh and 40% roof availability.

A few examples of yearly losses are given for different scenarios in Table 2. In the table, we note first that installing PV without a heat pump increases these losses significantly. Secondly, installing a moderate amount of PV together with a heat pump keeps these losses at an acceptable level. Finally, installing a large amount of PV, even when combined with a large heat pump, keeps these losses at a high level. This analysis assumes the presence of an energy community; not considering an energy community would render results similar to the case when no heat pump is installed.

Table 2: Economic losses due to yearly base-consumption contract in different scenarios.

PV capacity [MW] (Roof availability)	HP capacity [MW]	Losses [kEUR/year]
6 (20 %)	0	488
6 (20 %)	5.06	139
6 (20 %)	6.3	86
6 (20 %)	7.9	48
12 (40 %)	0	877
12 (40 %)	7.2	586
12 (40 %)	8.7	502
12 (40 %)	9.6	460

5. Conclusions

In this report, we explored practical designs for the energy system of the a university campus. We considered different levels of ambition for PV installations, uncertainties regarding the future price of biomass, and analyzed these designs in light of the current electricity tariff framework. These results are now brought together to provide key recommendations for the future development of the campus energy system. Given the high level of uncertainty surrounding biomass prices, sustainability concerns, and evolving policy frameworks, the university should adopt no-regret, resilience-driven strategies:

- The university should adopt a high level of ambition regarding PV installations. Under all scenarios, the PV capacity is installed up to the maximum available roof area. Only when no heat pump is installed does the PV capacity remain below its maximum, however still reaching 10.5 MW of installed capacity.
- Batteries can be economically profitable, with or without PV installations. However, the optimal level of battery deployment strongly depends on the installed PV capacity, the presence of a heat pump, and the formation of an energy community, and should therefore be aligned with a global system strategy. It is also expected that less battery capacity will be required as the yearly base-consumption contract is replaced by shorter-period contracts. Additional tailored analyses could be performed to determine optimal battery capacities for specific strategies. Finally, battery participation in electricity balancing markets is not considered in this report and could further improve battery profitability, potentially making battery deployment a no-regret option in all scenarios.
- The yearly base-consumption contract should gradually be replaced by shorter-period contracts as PV installations increase, as it constitutes a barrier to PV self-consumption and can have significant economic impacts.
- The university should further investigate the formation of an energy community, especially if a heat pump is installed. Not forming an energy community could lead to a loss of economic potential ranging from 40 to 300 kEUR/year as PV capacity increases. If no energy community is formed and no heat pump is installed, a more ambitious battery deployment should be considered to efficiently integrate PV production. In addition, without an energy community, the sequencing of PV and battery installations across buildings should be carefully designed to maximize building-level self-consumption, yielding shorter payback periods.
- Relying solely on biomass boilers to supply the campus heat demand is not advisable, as it becomes the most expensive solution when biomass prices reach 0.088 EUR/kWh and is consistently more costly than hybrid heat production systems. Given the concerns discussed in this report, the use of biomass for low-temperature heat generation should be avoided. From an economic perspective, design choices should account for an expected increase in biomass prices. An economically optimal, no-regret strategy that enhances the resilience of the campus heating system and enables a partial phase-out of biomass would consist of installing approximately 8 to 10 MW of heat pump capacity, 15 MW of biomass boilers, combined with a large PV capacity and 3 500 to 4 500 m^3 of heat storage. This strategy should be accompanied by the formation of an energy community and the adoption of shorter base-consumption contracts. Also, efforts to decrease the network temperature should be maintained and a solution to provide steam services to the CHU should be investigated.

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