

Article

Economic and Energy Efficiency of Bivalent Heating Systems in a Retrofitted Hospital Building: A Case Study

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Abstract

This case study evaluates the economic and energy efficiency of retrofitting a hospital heating system in Krakow, Poland, by transitioning from a district-heating-only model to a bivalent hybrid system. The analyzed configuration integrates air-to-water heat pumps (HP), a 180 kWp photovoltaic (PV) installation, and a 120 kWh battery energy storage (ES) unit, while retaining the municipal district heating network as a peak load and backup source. Utilizing high-resolution quasi-steady-state simulations in Ebsilon Professional (10 min time step) and projected 2025 market data, the study compares three modernization scenarios differing in heat pump capacity (20, 40, and 60 kW). The assessment focuses on key performance indicators, including Net Present Value (NPV), Levelized Cost of Heating (LCOH), and Simple Payback Time (SPBT). The results identify the bivalent system with 40 kW thermal capacity (Variant 2) as the economic optimum, delivering the highest NPV (EUR 121,021), the lowest LCOH (0.0908 EUR/kWh), and a payback period of 11.94 years. Furthermore, the study quantitatively demonstrates the law of diminishing returns in the oversized scenario (60 kW), confirming that optimal sizing is critical for maximizing the efficiency of bivalent systems in public healthcare facilities. This work provides a detailed methodology and data that can form a basis for making investment decisions in similar public utility buildings in Central and Eastern Europe.

Keywords: heat pumps; photovoltaic; energy storage; hybrid system; techno-economic analysis; energy efficiency; low-carbon; district heating; Ebsilon; ISO 52016-1:2017



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1. Introduction

Over the last decade, there have been a number of measures towards decarbonization taken by politicians and environmental movements based on climate issues [1–3]. The European Union, as a leader in these transformations, has set ambitious goals within the European Green Deal strategy [4,5] and the “Fit for 55” legislative package, aiming to reduce greenhouse gas emissions by at least 55% by 2030 and achieve climate neutrality by 2050 [6,7]. The building sector, responsible for approximately 40% of the final energy consumption and 36% of CO₂ emissions in the EU, plays a key role in this strategy [8–10]. The revised Energy Performance of Buildings Directive (EPBD) imposes an obligation on

member states to gradually phase out fossil fuels from heating systems and promotes the implementation of solutions based on renewable energy sources (RES) [5,11–14].

In parallel with the climate pressure, European countries, including Poland, are feeling the effects of instability in the global energy markets. Geopolitical issues have highlighted the strategic importance of energy security, understood as the ability to ensure reliable and affordable energy supplies. In this context, the diversification of sources and the development of local, distributed energy generation are becoming not only a tool of climate policy but also an element of building economic resilience [15–17].

Hospitals and other healthcare facilities represent a unique and critical challenge in this landscape. Their operation is characterized by a high, stable, and round-the-clock demand for energy, both thermal (heating, domestic hot water, and process steam) and electrical (medical equipment, lighting, and ventilation). The reliability of the power supply is an absolute priority here, as it is a prerequisite for patient safety. For this reason, the energy modernization of hospitals must be designed holistically, considering not only the potential for reducing costs and emissions but, above all, guaranteeing the continuity of operation [18–20].

In response to these challenges, hybrid renewable energy systems (HRES) have become a leading technological trend, widely analyzed in scientific literature, which integrate various energy generation and storage technologies. In the building sector, solutions based on the synergy of heat pumps (HP), photovoltaics (PV), and energy storage (ES) have gained particular recognition. Numerous studies consistently confirm the benefits of such integrations [21–23]. Works such as the analysis by [23,24] prove that the direct coupling of a PV installation with a heat pump allows for a significant increase in the self-consumption rate of renewable energy, which directly translates into lower operating costs. However, these authors, like many others, point to the fundamental challenge of the temporal mismatch between the PV generation profile (maximum in the middle of a summer day) and the heat demand profile (maximum on winter mornings and evenings). This problem is particularly acute in temperate climates, which include Poland [24–26].

The key solution to this problem is the inclusion of energy storage in the system. This can be both thermal storage (water buffer tanks) and electricity storage (batteries). Storage allows for the “shifting” of surpluses of cheap energy from periods of its overproduction to periods of increased demand, maximizing the use of RES and minimizing costly energy consumption from the public grid [27–29].

A particularly interesting area of research concerns the implementation of heat pumps in buildings that are already connected to a municipal district heating network. A comprehensive review indicates that heat pumps do not have to be an alternative to district heating but can cooperate with it effectively in a hybrid system [30–32]. In such a model, the heat pump works as the primary source, while the district heating network remains as a reliable peak source. This makes the costly and lengthy modernization of the entire network infrastructure unnecessary, which is a particularly promising model for Poland, where district heating systems are the backbone of heat supply in urban agglomerations [33–35].

1.1. Research Gap and Scientific Novelty

Techno-economic analyses for hospital buildings constitute a separate category of case studies due to their specific nature. While studies like [35–40] demonstrate the potential of trigeneration, and emphasize the importance of sizing in remote areas, a critical research gap remains regarding the optimal sizing of bivalent systems for energy-intensive public facilities connected to District Heating (DH) networks [12,19,41,42]. Most existing studies focus on residential buildings or complete off-grid solutions. There is a lack of high-resolution techno-economic analyses that specifically address the integration of heat pumps

with legacy DH infrastructure in the volatile economic context of Central and Eastern Europe [13,40,43]. Furthermore, standard hourly simulations often fail to capture the dynamic loads of hospitals, leading to sizing errors.

The main objective of this paper is to determine the optimal configuration of a hybrid energy system (Heat Pump + Photovoltaics + Energy Storage) for a representative hospital in Krakow, Poland. The study specifically aims to:

1. Estimate detailed CAPEX and OPEX for a baseline scenario versus three modernization variants (20 kW, 40 kW, and 60 kW thermal capacity) based on 2025 market data.
2. Identify the variant that maximizes Net Present Value (NPV) and minimizes the Levelized Cost of Heating (LCOH) while ensuring energy security.
3. Demonstrate the impact of oversizing on the project's profitability indicators.

The significance of this research extends beyond the case study. As European health-care facilities face the dual pressure of strict decarbonization targets (Fit for 55) and energy security threats, this article provides a validated roadmap for 'energy hedging'. We demonstrate how retrofitting existing buildings can freeze operational costs for decades and build resilience against market shocks, offering a strategic template for public utility buildings across the EU [44–48].

1.2. Financing Possibilities for the Thermal Modernization of Public Buildings in Light of EU Climate Policy—An Analysis and Assessment

In the European Union, as many as 85% of buildings were constructed before the year 2000, of which 75% are characterized by low energy efficiency [10,44–46,49]. For this reason, improving the energy performance of existing buildings is crucial to reducing energy consumption, lowering costs borne by citizens, public facilities, and businesses, as well as achieving climate neutrality and the full decarbonization of the building sector by 2050. Despite this, the rate of energy renovation remains low—only around 1% annually [22,27].

The implementation of the revised Energy Performance of Buildings Directive, published in May 2024 [14], has contributed to strengthening the European Union's energy independence and enhancing its energy security. At the same time, it has enabled a reduction in energy costs for users, improved living conditions, and lessened the need for further investment in energy infrastructure. The directive serves as a key instrument in supporting the EU's energy efficiency target of reducing energy consumption by 11.7% by 2030. It will also foster greater use of renewable energy sources in buildings. Furthermore, its implementation is expected to positively impact the competitiveness of the EU's construction sector and the clean technology industry. Directive (EU) 2024/1275 of the European Parliament and the Council of the European Union, 24.04.2024 [14], promotes the improvement of the energy performance of buildings and the reduction in greenhouse gas emissions from buildings in the Union with the aim of achieving a zero-emission building stock by 2050. This objective takes into account external climatic conditions, local circumstances, requirements for indoor environmental quality, and economic cost-effectiveness.

Public buildings can obtain financial support from several sources, with European Union projects being among the most popular. One such initiative is the European Funds for Infrastructure, Climate and Environment Programme (FEnIKS) [20,49,50]. This program was developed to support the sustainable development of the country by expanding modern technical and social infrastructure. Its overarching goal is to improve the quality of life for citizens and to create a strong foundation for a competitive and crisis-resilient economy. The measures undertaken within the program will be implemented in line with the principles of sustainable development, which integrate environmental protection, economic growth, and social progress. Particular emphasis is placed on reducing greenhouse gas emissions and transitioning to a more environmentally friendly economic model based

on the principles of the circular economy. This transformation will be supported by investments in an efficient and resilient transport system that minimizes its negative impact on the natural environment.

In the energy sector, the program focuses on improving the energy efficiency of residential buildings, public facilities, and enterprises. A key priority is also to increase the share of renewable energy in total energy consumption. At the same time, modern energy infrastructure will be developed—particularly smart gas and electricity grids—with the aim of enhancing the security and reliability of energy supply.

These renovation efforts are encouraged by financial incentives designed to address the poor energy performance of 75% of EU buildings. As illustrated in Figure 1, Polish support mechanisms include the Thermomodernization Bonus, which co-finances up to 31% of investment costs for projects that include RES installations, and the comprehensive FEnIKS Program, both of which support the EU's goal of achieving climate neutrality by 2050.

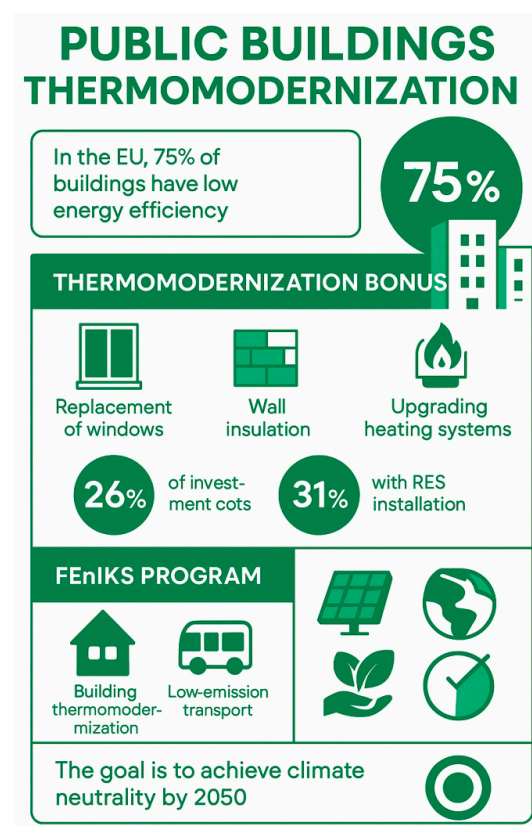


Figure 1. Public building thermomodernization.

Support is available for projects implemented at both local and national levels, provided they contribute to improving energy efficiency and climate protection. To be eligible for funding, a project must fall within one of the supported areas, such as renewable energy sources, water management, building thermal renovation, or low-emission transport. The investment must meet environmental criteria and contribute to reducing CO₂ emissions. The level of funding depends on the scale of the project and the type of beneficiary.

In line with the European Green Deal, and the Legal documents on Delivering the European Green Deal [5], the Union has committed to addressing energy, climate, and environmental challenges and achieving climate neutrality by 2050, in accordance with the Paris Agreement. The transformation of the EU's energy system plays a crucial role in this process, as both energy production and consumption account for over 75% of greenhouse gas emissions in the EU.

The Renewable Energy Directive, which entered into force in November 2023, is a key instrument in this transition. Directive (EU) 2023/2413 of the European Parliament and the Council amending Directive (EU) 2018/2001; Regulation (EU) 2018/1999 and Directive 98/70/EC, regarding the promotion of energy from renewable sources; and repealing Council Directive (EU) 2015/652 [44] raise the 2030 target for renewable energy to 42.5%, with EU Member States encouraged to strive for 45%. This directive accelerates permitting procedures for new renewable energy installations, such as solar panels or wind turbines, and sets a maximum approval period of 12 months for projects located in renewable energy priority areas, and 24 months for those outside these areas thanks to Commission Implementing Regulation (EU) 2020/1294 on the Union renewable energy financing mechanism. An EU-level financing mechanism was established under Regulation (EU) 2020/1294 to help Member States achieve both their individual and collective renewable energy targets. This mechanism links contributing countries, which provide funding for renewable energy projects, with host countries that agree to implement new projects on their territory [5,14,44–46,49,51].

The thermomodernization bonus is granted to an investor in connection with the implementation of a thermal renovation project and takes the form of a partial repayment of the loan taken out to finance the investment. This means it is available only to investors who finance their projects with a loan—it does not apply to those covering the costs solely from their own funds. The loan must amount to at least 50% of the total investment cost and cannot be lower than the value of the eligible bonus [50,51].

The standard amount of the thermomodernization bonus is 26% of the investment costs. However, if the thermal renovation project is combined with the installation of renewable energy sources (RES)—such as the purchase, installation, or upgrade of RES systems—the support increases to 31%. In such cases, RES-related costs must account for at least 10% of the total eligible expenditure [51].

In response to these challenges, the revised Energy Performance of Buildings Directive was published in May 2024. Its aim is to accelerate the modernization of both public and private building stocks. It introduces the obligation to develop national renovation plans and to install solar energy systems in new and existing non-residential buildings. By 2030, all public buildings with a usable floor area above 250 m² are to be equipped with such installations, provided this is technically feasible and economically viable [52–57].

This publication aims to fill this research gap. The main objective of this paper is to fill the identified research gap by conducting a detailed techno-economic analysis of three modernization variants for the heat supply system of a representative hospital facility in Krakow. The paper seeks to answer the key research question: What is the optimal configuration of a hybrid energy system for a Polish hospital connected to a district heating network, which maximizes economic benefits while ensuring a high degree of energy security?

This study addresses these gaps by introducing three key innovations:

1. Unlike broad hourly models, this study applies a 10 min time step quasi-steady-state simulation. This granularity is crucial for accurately capturing the transient cooperation between the PV generation peaks, battery storage dynamics, and the thermal inertia of the hospital's heating system.
2. The paper moves beyond simple feasibility to explicitly analyze the economic saturation point. By comparing incrementally scaled variants (20, 40, and 60 kW), we quantitatively demonstrate the 'law of diminishing returns', providing a clear warning against oversizing in public investments.

3. We propose a reproducible methodology for transforming District Heating from a primary source into a strategic peak/backup source, enhancing energy security without the need for costly total infrastructure replacement.

To achieve the main objective, the following specific objectives have been formulated:

- To estimate the detailed capital expenditures (CAPEX) and annual operating costs (OPEX) for the baseline scenario and the three modernization variants, based on current market prices.
- To determine and compare key profitability indicators, including the Simple Payback Period (SPBT), in order to objectively assess the viability of the analyzed scenarios.
- To identify the optimal modernization variant that represents the best compromise between the investment amount, the level of generated savings, and the degree of energy independence achieved.
- To conduct a sensitivity analysis of the results to changes in key economic parameters, such as energy and heat prices.
- To provide a comprehensive and repeatable assessment methodology that can be adapted for the analysis of similar modernization projects in the public sector in Poland and the region.

Our primary methodological contribution is the application of a high-resolution, quasi-steady-state simulation (using a 10 min time step) to specifically address the optimal sizing of a heat pump in a hybrid configuration. Unlike broader studies, our model integrates an air-to-water heat pump (HP), photovoltaics (PV), and electrical energy storage (ES) with an existing municipal district heating (DH) network, which is retained as a peak/backup source [58,59]. The core of our methodology is the direct comparison of three distinct, incrementally scaled power variants (20, 40, and 60 kW), allowing for a precise identification of the point of diminishing economic returns—a critical factor often highlighted but rarely analyzed with this granularity in hospital case studies. This work provides a unique and timely techno-economic dataset specific to a public hospital in Krakow, Poland, using current 2025 market data. Our contribution includes: detailed CAPEX breakdowns for commercial-grade heat pumps, photovoltaic, and energy storage systems, and OPEX calculations based on actual 2025 tariffs for business customers from local suppliers (MHPC for district heat and Tauron for electricity). It also includes granular annual energy performance data for a representative hospital building under different hybrid system configurations, detailing the dynamic interplay between on-site generation, storage, grid consumption, and reliance on the legacy district heating network. The analysis employs a comprehensive economic model that moves beyond the static Simple Payback Time (SPBT). To provide a robust basis for long-term investment decisions, the study explicitly includes dynamic lifecycle metrics, specifically Net Present Value (NPV), Annual Equivalent Cost (AEC), and the Levelized Cost of Heating (LCOH), taking into account energy price escalation and the time value of money [8,22,26,42]. While our model briefly assesses a series configuration, we found the performance difference to be negligible for the low-temperature heating system in this specific case. Therefore, our conclusions do not extend to high-temperature heat pump applications where series arrangements can offer more significant efficiency gains. The analysis is confined to the building's heating demand and does not consider the potential for operating the heat pumps in reversible mode to meet summer cooling loads [60].

2. Materials and Methods—Methodology

This case study describes how an existing heating system of a public building, a hospital, can be improved in terms of economic and ecological efficiency by adding a heat pump. The key factor in the economic viability of the modernization is providing a

heat pump for only a partial load of a building. An additional buffer tank and PV system increase feasibility. The methodology uses heat pump simulation based on historical meteorological data and the design load of an analyzed building—the methodology is based on a model presented in a previous paper [26,28]. The model was developed in Ebsilon professional software version 16.00. By using a non-linear system of equations, solved using a Newton-like linearization and a matrix solution, calculations consist of thermodynamic parameters of mediums in every part of a cycle. The calculations produce results in the form of series of quasi-steady states on a time step.

The calculation procedure can be separated into the two main steps:

- Building heat calculations resulting in the design heat load of the building for different temperatures and solar gains. The values are approximated by ambient temperatures and solar irradiance, respectively. The model is based on the construction project of the building, and the calculation methodology used in certification and energy auditing of the buildings.
- Simulation of the heating system in a quasi-steady state in the Ebsilon environment using a 10 min time step and meteorological data for temperatures and irradiance. The feed data for the model are the meteorological data, while assumptions are made on the design size of the heat source and buffer tank. The heat calculations provide the characteristics for actual heat demand.

2.1. Transient Heat Pump Model

The model was simulated using Ebsilon Professional software, which solves a non-linear system of equations based on the fundamental principles of mass and energy conservation for each component. This ensures that all thermodynamic calculations are physically consistent, and the mass and energy balance is internally verified at each time step. The governing equations are solved using a Newton-like linearization method to find a convergent solution for each quasi-steady state. To ensure the accuracy and stability of the results, a rigorous quantitative convergence criterion was applied: the calculations for a single step (typically requiring 100–1000 iterations) are stopped only when the maximum residual error drops below 10^{-6} .

The main source and sink terms are treated as boundary conditions. These include the building's heat load, the outdoor air temperature, and the global solar irradiance. The heat load was correlated to the ambient temperature by a linear function. Solar gains, based on the building model, were subtracted from the overall heat load and correlated to solar irradiance [47,61]. The municipal district heating network and the power grid are modeled as infinite sources or sinks, supplying any energy deficit or absorbing surpluses according to the control logic.

The meteorological data was provided by the PVGIS database [61,62] for the location in Krakow, Poland. The data ranged from October 2023 to April 2024, covering a single heating season. The dataset consisted of solar irradiance, outdoor temperature, and wind speed with an hourly time step. Studies [24,37,62] provide a benchmark for difficult locations and an overall analysis of model error, concluding that the PVGIS model is characterized by an RMSE and MABE of less than 2% in almost all cases, which is similar to the accuracy of ground-based measurements. In the case of temperature analysis performed for a Typical Meteorological Year (TMY), Refs. [40,43] reported RMSE results between 3.98 and 4.27 for different model variants.

The selected period (2023/2024) represents a standard heating season for the current climatic conditions in Poland, characterized by milder winters compared to historical averages from the 20th century. The analysis of the 2023/2024 data against the TMY for Krakow reveals that while the average temperatures were higher (leading to a lower

total heating demand), the solar irradiance profiles remained consistent. Regarding long-term predictions, relying on this recent dataset provides a more realistic forecast for the system's lifecycle (2025–2045) than using historical TMY data, which often overestimates heat demand in the face of climate change. Furthermore, in the event of a colder-than-average winter, the hybrid nature of the system mitigates operational risk: the deficit would be covered by the District Heating network (peak source). From an economic perspective, a colder season could arguably improve profitability, as the base-load heat pumps would operate at full capacity for extended periods, displacing a larger volume of the most expensive district heating units.

The time step was adapted to 10 min by interpolating the hourly data. The step size was decreased to account for dynamic changes in the buffer tank and to provide a compromise between capturing system dynamics and computation time. Work regarding the time step [61,62] shows that using an hourly time step (as in the raw meteorological data) can cause significant discrepancies in the results.

The model (Figure 2) consists of several different connection types:

- The heating system piping, using water as the heat transfer medium, represented by the blue line. This system represents the hydraulic connection of heat pump system. Peak heat source—district heating, buffer tank, and connection to the building heating system. Heat sources deliver the heat to the water connected to the buffer tank. The temperature of the medium is set to be 5 K higher than the tank temperature. Increasing the overheat would lead to higher heat pump temperature lift, causing a decrease in efficiency. The heating system in the building is controlled by the building's heat load. The temperature drop in the system is set to a constant value of 12 K, corresponding to ISO 52016-1:2017 [63] for a floor heating system.
- The electrical system is represented by magenta lines. The PV system supplies power to the inverter and is connected to the external grid, transferring power to the heat pump system. The PV system's effectiveness is calculated using global irradiance historical meteorological data and sun angles. The PV component uses the current–voltage relationship to derive the maximum power point (MPP), with parameters provided by the manufacturer.
- The remaining thin lines represent logic connections used to control the components in the time series. The controllers use EBSscript, a language based on PASCAL syntax.
- Heat pump production is controlled by the buffer tank temperature, building demand, and PV production. The minimum temperature in the buffer tank is maintained at 35 °C. The availability of PV energy triggers heat production up to a temperature of 50 °C in the buffer tank. Additional control logic is implemented to compensate for heat losses and maintain continuous operation.
- The heat pump system is configured to use only the required number of units at any given moment. The thermal power of a single unit is calculated based on its performance characteristics. In variants using multiple heat pump units, exceeding the current thermal power capacity of a single unit triggers an additional unit to operate in cascade. This control scheme optimizes the load distribution among the heat pumps.
- The meteorological data (solar irradiance, temperature, and wind speed) were obtained from the PVGIS database with a native hourly resolution. To align with the simulation's requirements, these data were adapted to a 10 min time step using linear interpolation.
- The choice of a 10 min step, despite the hourly input, is strictly dictated by the dynamic control logic of the Energy Storage (ES) and the thermal inertia of the buffer tank. Standard hourly simulations average out solar generation peaks, which frequently leads to an underestimation of battery saturation events and an overestimation of RES

self-consumption. By using a 10 min step, the model accurately captures intra-hour dynamics—such as rapid battery charging during peak irradiance or short-cycling of the heat pump—ensuring that the calculated Key Performance Indicators (KPIs), particularly the OPEX and self-consumption rates, are robust and not artificially smoothed.

- The exact algorithm governing the control of the time series calculations remains unchanged from the one used in the previous paper [28].

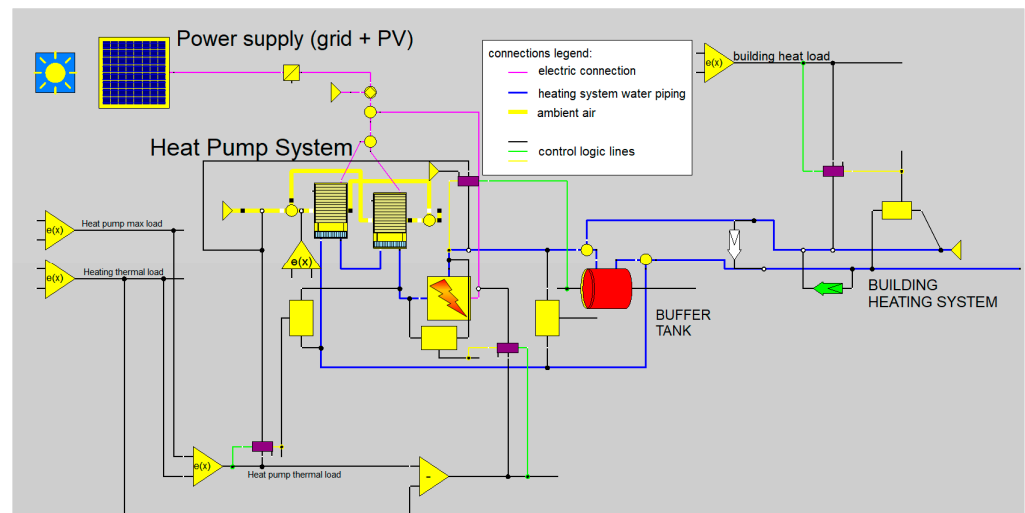


Figure 2. Graphic representation of simulated model in Ebsilon software.

The heat pump component is controlled by performance maps for calculation of the COP value and the maximum heating capacity of the unit. In both cases, the values depend on the heat source and heat sink temperatures. The inputs for these specifications are derived from data provided by the manufacturer. In compliance with EU regulation No. 813/2013, the manufacturer provides a COP and heating capacity for outlet temperatures of 35 °C and 55 °C and four outdoor air temperature levels: −7 °C, 2 °C, 7 °C, and 12 °C. The data in the matrices were interpolated using a bicubic algorithm and extrapolated using the nearest neighbor method. If the heat pump capacity in the model is insufficient to cover the building heat load, the existing connection to the district heating network is utilized as a peak source [32,64].

The simulation was performed for three variants, with an increasing number of heat pump units connected in a parallel configuration. Spanning a range from 1 to 3 units, the proposed system provides a nominal thermal output of 20 to 60 kW (20 kW per unit). It is important to note that at the lowest analyzed operating temperature of −10 °C, the heating capacity of a single unit drops to 15.5 kW, whereas at higher ambient temperatures (>7 °C), it increases to 30 kW. This fluctuation significantly impacts the overall performance of the heat pump system.

2.2. Description of the Analyzed Object and System

2.2.1. System Sizing and Configuration Rationale

The sizing of the hybrid system components was based on a modular and techno-economic optimization strategy rather than arbitrary selection:

- The analysis adopts a modular approach using a commercial-grade 20 kW air-to-water monobloc unit as the base module. The variants (20, 40, and 60 kW) were selected to analyze the economic efficiency of covering different shares of the building's thermal load. The intention was explicitly not to cover the peak thermal load (which would require oversizing), but to identify the optimal base-load capacity that cooperates with the district heating network.

- The capacity of 180 kWp was dimensioned to achieve an annual energy production of approximately 180 MWh. This value was targeted to balance the electrical demand of the heat pump system on an annual basis, aiming for a “net-zero” heating solution, while remaining within the physical constraints of the hospital’s available roof area.
- The 120 kWh capacity was selected as an economic trade-off between investment costs (CAPEX) and functionality. It is sized to facilitate daily energy time-shifting—storing the mid-day generation peak for use during evening peak demand—without aiming for prohibitively expensive seasonal storage.

Furthermore, the selection of these components was strictly dictated by the specific operational profile of the healthcare facility. Unlike office or educational buildings, the hospital operates on a continuous 24/7 basis, generating a stable and high demand for thermal energy (heating and domestic hot water) and electricity throughout the night. This specific load profile is the primary justification for integrating the 120 kWh energy storage unit, which allows for the effective utilization of daytime PV surpluses to cover the facility’s continuous night-time consumption, thereby maximizing the system’s economic efficiency.

The subject of the analysis is a hospital building located in Krakow (Figure 3). It is a facility with characteristics typical of Polish hospital construction from the second half of the 20th century, which has undergone partial thermal modernization. A key feature of the facility is its year-round, high demand for heat (for heating and domestic hot water preparation) and electricity.

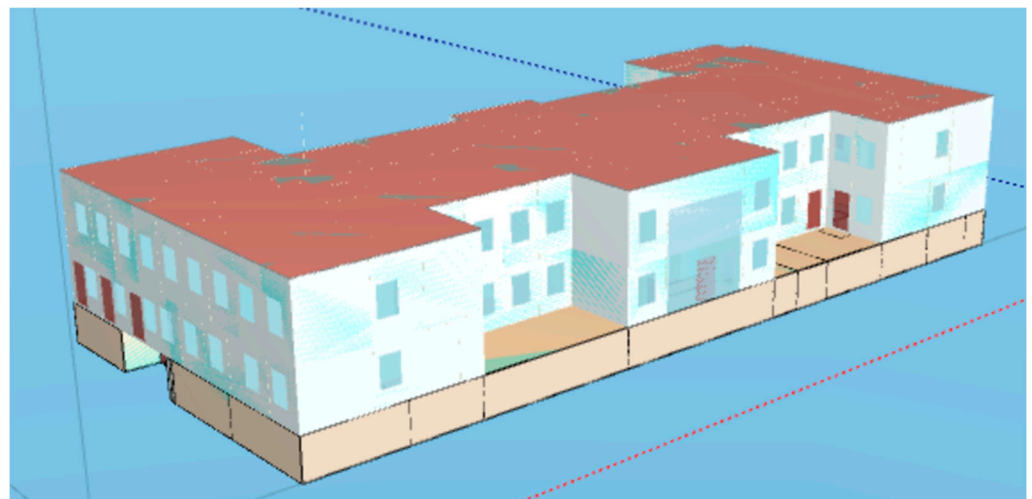


Figure 3. The hospital building’s energy model, developed in Audytor OZC software version 7.0.

The building’s thermal insulation quality is varied:

- Roof: U-value = $0.120 \text{ W/m}^2\text{K}$ (required: 0.150).
- Exterior walls: U-value = $0.187 \text{ W/m}^2\text{K}$ (required: 0.200).
- Basement floor: U-value = $0.231 \text{ W/m}^2\text{K}$ (required: 0.300).
- The main building partitions meet and even exceed the requirements, which indicates relatively low heat loss through transmission via these elements.
- Exterior windows: U-values range from 1.3 to $1.7 \text{ W/m}^2\text{K}$, while the current requirement is $0.9 \text{ W/m}^2\text{K}$. The windows are the primary weak point of the building’s thermal envelope and generate significant heat loss.
- Exterior doors: The U-value is $1.3 \text{ W/m}^2\text{K}$, which barely meets the requirement and is far from modern standards.

2.2.2. Baseline Scenario (Variant W0)

This physical state defines the baseline scenario (Variant W0). The hospital building is characterized by very high energy consumption, confirmed by the non-renewable primary energy (EP) indicator of 507.2 kWh/(m²·year). This value is almost twice as high as the 265.0 kWh/(m²·year) requirement for new buildings. The high demand for usable energy (EU = 187.5 kWh/m²·year) is dominated by domestic hot water preparation (66.3%). The large gap between usable energy and final energy (EK = 394.1 kWh/m²·year) indicates the low efficiency of the internal technical systems. The share of renewable energy sources in the balance is negligible, at only 1.4%.

In the initial state, 100% of the heat demand is covered by the municipal district heating network, MHPC Krakow (Municipal Heat and Power Company S.A. Krakow, Poland). All electricity is drawn from the grid of the distribution system operator (TAURON Distribution S.A., Krakow, Poland).

2.2.3. Modernization Scenarios (V1, V2, V3)

Three modernization variants were analyzed, in which the MHPC system remains as a peak/backup source, and a hybrid system is installed as the primary heat source, consisting of:

- Heat Pumps (HP): Air-to-water compression heat pumps, operating in a parallel system. The nominal power of each unit is 20 kW. The variants differ in the number of units:
 - V1: 1 HP unit (total nominal power 20 kW)
 - V2: 2 HP units (total nominal power 40 kW)
 - V3: 3 HP units (total nominal power 60 kW)

Based on the data provided by the manufacturer, a variable operating characteristic for the pumps was assumed. The boundary value of the thermal power drops to 15.5 kW at an ambient temperature of −10 °C and increases to 30 kW at ambient temperatures reaching above 7 °C.

- Photovoltaic (PV) installation: A rooftop PV installation with a peak power of 180 kWp, which is constant for all variants.
- Energy storage (ES): A battery electricity storage system with a capacity of 120 kWh, which is constant for all variants.

2.3. Economic Model and Assumptions

The economic analysis was conducted using a comparative method, contrasting the annual costs for the baseline scenario (Variant W0, 100% reliance on the MHPC district heating network) with the three modernization variants (V1, V2, and V3). The primary objective of this comparison is to quantify the financial viability of the investment and identify the optimal system configuration.

To achieve this, the model evaluates the total Capital Expenditure (CAPEX) required for each variant, calculates the new annual Operating Costs (OPEX), and determines the resulting annual savings against the baseline. These core figures are then used to assess profitability through key indicators. While the initial assessment focuses on the Simple Payback Time (SPBT), the analysis is extended to include dynamic lifecycle metrics such as Net Present Value (NPV), Annual Equivalent Cost (AEC), and the Levelized Cost of Heating (LCOH) to provide a comprehensive basis for the investment decision.

2.3.1. Capital Expenditure (CAPEX)

The total capital expenditure ($\text{CAPEX}_{\text{total}}$) was calculated as the sum of the costs of the individual system components and additional costs:

$$\text{CAPEX}_{\text{total}} = \text{CAPEX}_{\text{HP}} + \text{CAPEX}_{\text{PV}} + \text{CAPEX}_{\text{ES}} + \text{CAPEX}_{\text{add}} \quad (1)$$

where

- CAPEX_{HP} : Cost of purchase and installation of the heat pumps, dependent on the variant.
- CAPEX_{PV} : Cost of the “turnkey” photovoltaic installation.
- CAPEX_{ES} : Cost of the battery energy storage system including the management system (BMS).
- $\text{CAPEX}_{\text{add}}$: Costs of the project design, adaptation works, the hydraulic system, heat buffers, and control automation, assumed as a percentage of the sum of the main costs.

2.3.2. Operating Costs (OPEX)

The annual operating costs (OPEX_{var}) for the modernization variants were calculated according to the formula:

$$\text{OPEX}_{\text{var}} = C_{\text{MHPC}} + C_{\text{grid}} - R_{\text{PV}} + C_{\text{O\&M}} \quad (2)$$

where

- C_{MHPC} : Annual cost of purchasing heat from the MHPC network (amount of heat from MHPC [kWh] $\times$ Unit price of heat [EUR/kWh]).
- C_{grid} : Annual cost of purchasing electricity from the grid for the needs of the heat pumps (amount of energy from the grid [kWh] $\times$ Unit price of electricity [PLN/kWh]).
- R_{PV} : Annual revenue from the sale of surplus energy from the PV installation to the grid (amount of energy sold to the grid [kWh] $\times$ Market sale price [EUR/kWh]).
- $C_{\text{O\&M}}$: Annual costs of service, maintenance, and insurance for the system, assumed as a percentage of the total CAPEX value.

2.3.3. Profitability Indicators

The main indicator for assessing profitability was the Simple Payback Time (SPBT), calculated as:

$$\text{SPBT [years]} = \text{CAPEX}_{\text{total}} / \text{Annual savings} \quad (3)$$

where

- Annual savings = $\text{OPEX}_{\text{W0}} - \text{OPEX}_{\text{var}}$
Data sources and pricing assumptions:
The analysis was based on two pillars of data.
- Energy Data: The annual energy flows for each variant were taken directly from the simulation results as well as from actual data from the billing records provided by the hospital.
- Cost Data: Investment costs and energy prices were estimated based on an analysis of the Polish market for the year 2025. Average prices for business customers were assumed (B23 tariff for electricity, the business tariff for MHPC Krakow) as well as the market resale price for energy in the net-billing system (monthly market price—RCEm). The detailed values of the assumed prices and unit costs have been presented in previous iterations of the analysis.

3. Key Assumptions and Data Sources

3.1. Energy Data from the Simulation

The analysis is based on the following annual data, obtained from the simulation. This data forms the foundation for the cost and savings calculations (Table 1).

Table 1. Parameters used for control and as results in the simulated model.

Parameter	Units	Variant 1 (1 HP)	Variant 2 (2 HP)	Variant 3 (3 HP)
Heat supplied by the HP	kWh	107,319.86	180,703.07	218,581.44
Heat drawn from the DHC	kWh	132,273.24	60,317.64	20,623.29
Grid electricity for the HP	kWh	25,075.35	46,020.94	59,985.10
PV electricity for the HP	kWh	9452.99	14,176.54	17,224.51
Total electricity consumption by the HP	kWh	34,528.34	60,197.48	77,209.62
PV electricity exported to the grid	kWh	169,912.51	165,188.96	162,140.99

The chart presented in Figure 4 illustrates the fundamental change in the method of supplying heat to the hospital, which occurs after the implementation of the successive modernization variants.

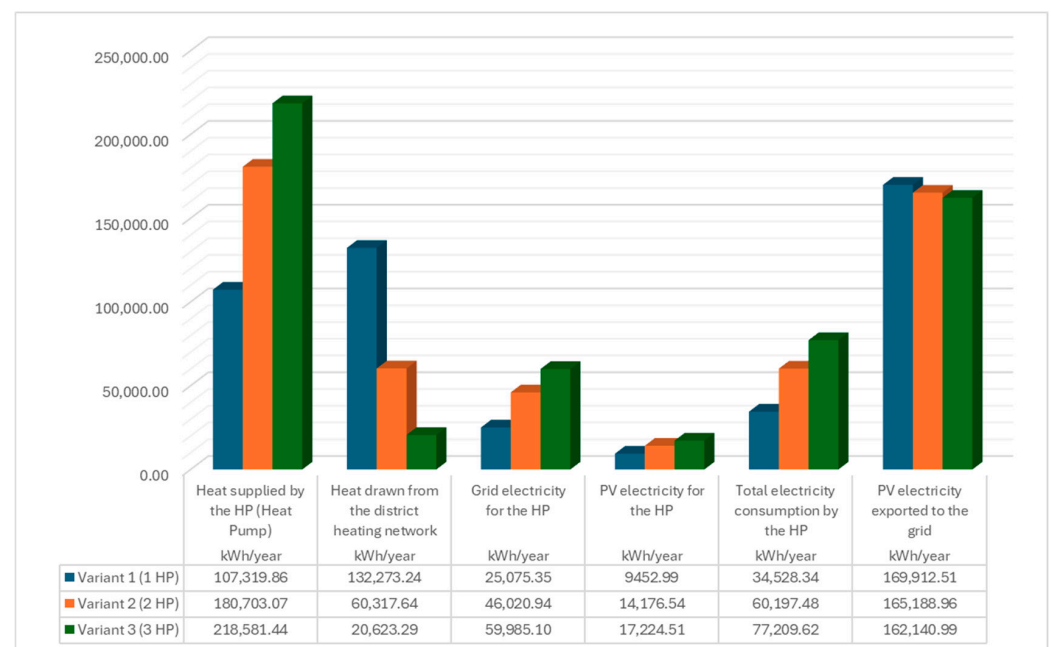


Figure 4. Parameters used for control and as results in the simulated model.

- Already in Variant 1, the heat pumps become a significant source of heat, supplying 107,319.86 kWh, which constitutes almost a half of the energy. However, there is still a large demand for supplemental heating from the MHPC network, amounting to 132,273.24 kWh.
- The most striking change occurs when moving from Variant 1 to Variant 2. Doubling the number of heat pumps causes a drastic reduction in the amount of heat drawn from MHPC—from over 132,273 kWh to just 60,317 kWh (a 54% decrease). The share of the heat pumps becomes absolutely dominant, covering almost the entire demand.
- Variant 3 shows a state close to full independence from the district heating network. The amount of heat drawn from MHPC drops to a symbolic level of 20,623 kWh which constitutes less than 8.62% of the total demand. This means that the MHPC network now only serves as a peak backup source in case of extremely low temperatures or failure.

Figure 4 shows that each successive modernization variant effectively displaces the expensive and less ecological district heat, replacing it with energy produced on-site by the heat pumps. The visualization confirms the conclusion from the economic analysis—the greatest progress in reducing dependence on MHPC is achieved in Variant 2, which makes it the “golden mean” of the investment. Variant 3 is merely a completion providing almost total thermal autonomy. Figure 4 shows what portion of the total annual heat demand is covered by the new heat pumps, and what portion still needs to be supplied by the municipal district heating network (MHPC).

The system operates in a bivalent-parallel mode, where the heat pump system is the primary source, and the municipal district heating network (MHPC) serves as the peak/backup source. The overarching goal is to maximize the use of heat from the heat pumps—largely powered by free energy from the photovoltaic installation—while minimizing the consumption of more expensive heat from the DH network. The central element controlling the entire system is the temperature within the buffer tank.

The main handover threshold is based on a power balance. The district heating substation is activated automatically whenever the thermal power supplied by the heat pump system is insufficient to meet the building’s current heat demand. In practice, the simulation algorithm compares the calculated building heat load with the maximum available power of the heat pumps under the given conditions (which decreases as the outdoor temperature drops) at each time step. If the demand exceeds the HP’s production capacity, the difference is immediately covered by the DH network. The controller aims to maintain a minimum temperature of 35 °C in the buffer tank to ensure a constant supply of heat for the heating installation. When free energy is available from the photovoltaic installation, the control logic allows the heat pumps to operate at a higher output to “overcharge” the buffer up to a maximum temperature of 50 °C. This allows energy to be stored as heat and used in later hours.

Our model assumes a constant temperature drop of 12 °C across the building’s internal heating system, which is a typical value for a heating system. It is important to note, however, that the model did not account for specific constraints imposed by the DH operator (MHPC) regarding the maximum temperature of the water returning to the district heating network. In a real-world implementation, this is a critical technical parameter that would need to be addressed in the substation design. For the purposes of this simulation analysis, however, it was not an active constraint.

3.2. Assumptions for Capital Expenditures (CAPEX)

The costs were estimated based on market prices for commercial-grade components in Poland in 2025.

- Heat pumps (HP): Monobloc compression air-to-water heat pumps with a nominal capacity of 20 kW each.
 - Unit cost including installation: 21,177 EUR/unit.
 - Justification: The price includes high-efficiency, reversible air-to-water monobloc units, optimized for operation in Polish climate conditions. The cost includes basic automation, installation, and integration with the hospital’s existing hydraulic system.
- Photovoltaic (PV) installation: The simulation indicates an annual production of approx. 180 MWh/year, which corresponds to an installation with a capacity of approx. 180 kWp.
 - Unit cost (turnkey): 824 EUR/kWp.

- Justification: The installation capacity (180 kWp) was selected based on the annual production from the simulation (~180 MWh), assuming a standard yield for Poland at the level of 1000 kWh/kWp/year. The unit price is a “turnkey” price for a commercial installation and includes panels, inverters, the mounting structure, cabling, and protective equipment, as well as design and installation costs.
- Energy storage (ES): An electrical energy storage system is necessary to optimize self-consumption. A capacity adequate for the PV installation’s power was assumed.
 - Unit cost: 517.66 EUR/kWh.
 - Assumed capacity: 120 kWh.
 - Justification: Energy storage is a key element of the system allowing for the maximization of self-consumption. It enables the storage of surplus energy from the PV system during the day and its use during the evening and night hours, when the hospital’s energy demand is still high, and grid electricity prices are at their highest. The 120 kWh capacity represents a trade-off between the ability for energy time-shifting and the investment cost.
- Additional system elements: These include the buffer tanks (2×1000 L), the hydraulic system, and the control system, as well as design and adaptation works.
 - Estimated as 15% of the main component costs.
 - Justification: This item covers the necessary costs that are difficult to estimate precisely at this stage, such as the high-capacity buffer tanks (min. 2000 L), an advanced Energy Management System (EMS), adaptation works in the boiler room, detailed design costs, and unforeseen expenses.

3.3. Assumptions for Operational Expenditures (OPEX)

- Price of heat from MHPC Krakow: Based on the business tariff, an averaged variable, and fixed price.
 - Price: 0.106 EUR/kWh (106 EUR/MWh).
- Price of electricity from the grid (Tauron): B23 tariff for business customers, and average price of active energy and distribution fees.
 - Purchase price: 0.212 EUR/kWh (211.77 EUR/MWh).
- Resale price of energy from PV: In accordance with the net-billing system, a conservative monthly market price of energy (RCEm) was assumed.
 - Sale price: 0.118 EUR/kWh (118 EUR/MWh).
- Service and maintenance (O&M) costs: Annual flat rate.
 - Value: 1.5% of total capital expenditures (CAPEX).
 - Justification: This is a standard indicator for energy systems (1.5% of CAPEX annually). Over the 20-year lifecycle, this accumulates to 30% of the initial investment. This provision is intended to cover not only annual inspections, insurance, and minor consumables but also to amortize the costs of major component replacements (e.g., PV inverters or battery cell servicing) anticipated during the project lifespan [42].

The prices for operational expenditures were assumed based on a detailed analysis of the MHPC Krakow and Tauron tariffs for business customers (specifically the B23 tariff group) for the year 2025. This resulted in an average price for district heat from MHPC of 0.106 EUR/kWh and an average purchase price for grid electricity (including active energy and distribution fees) of 0.212 EUR/kWh.

For revenues, the model assumes surplus energy from the 180 kWp PV installation is sold to the grid under the net-billing system. The resale price is based on a conservative

forecast of the monthly market price of energy (RCEm) on the TGE (Polish Power Exchange), estimated at 0.118 EUR/kWh.

The high purchase price of electricity (0.212 EUR/kWh) compared to the significantly lower resale price (0.118 EUR/kWh) creates a critical economic incentive. This spread highlights the clear economic rationale for maximizing the on-site self-consumption of generated PV electricity. This, in turn, is the primary justification for the investment in the 120 kWh battery energy storage system (ES). The ES is essential to the system's profitability, as it allows surplus solar energy generated during the day to be stored and used during evening and night hours, when the hospital's demand is still high, but grid prices would otherwise apply.

4. Investment Analysis: CAPEX, Risks, and Non-Financial Benefits

Table 2 below presents the detailed calculations of capital expenditures for each variant. The costs were estimated based on market prices for commercial-grade components in Poland in 2025.

Table 2. Capital expenditures.

Component	Variant 1 (1 HP)	Variant 2 (2 HP)	Variant 3 (3 HP)
Heat Pumps (EUR)	21,177	42,354	63,531
PV Installation (EUR)	148,239	148,239	148,239
Energy Storage (EUR)	62,119	62,119	62,119
Total primary costs (EUR)	231,535	252,712	273,889
Additional costs (15%) (EUR)	34,730	37,907	41,083
Total CAPEX (EUR)	266,265	290,619	314,972

As shown in Table 2, the base investment cost for the main RES technologies (PV + Energy Storage) is constant across all variants. This fixed cost of EUR 210,358 includes a 180 kWp rooftop photovoltaic installation, costed at 824 EUR/kWp, and a 120 kWh battery electricity storage system, costed at 517.66 EUR/kWh.

The differences in total CAPEX are solely due to the incremental increase in the number of heat pumps and the corresponding proportional increase in additional costs. The cost of Heat Pumps is based on a unit price of EUR 21,177 for each 20 kW monobloc air-to-water unit. Additional costs, which cover buffer tanks (2×1000 L), the hydraulic system, control automation, and design works, were estimated as 15% of the main component costs.

This structure clearly shows the linear nature of the investment growth. Variant 2 (total CAPEX EUR 290,619) is approximately 9% more expensive than Variant 1 (EUR 266,265), and Variant 3 (EUR 314,972) is about 8% more expensive than Variant 2.

A complete project assessment must take into account factors beyond the purely financial aspects of capital expenditure shown in Table 2. While CAPEX is a key driver, a comprehensive assessment must also consider potential risks and significant non-financial benefits that impact the project's long-term value and strategic alignment.

Table 3 presents a qualitative summary of these key factors. It categorizes the identified risks into financial, technical, and operational areas. At the same time, it highlights the key strategic non-financial benefits, including reputational gains (ESG/CSR), a significant increase in energy security, and a direct contribution to CO₂ emissions reduction.

Table 3. Risks and benefits.

Category	Type	Detailed Description
<u>RISKS</u>	Financial & Market	Regulatory Risk: Potential adverse changes to the net-billing settlement system for PV energy sales. Price Volatility: A significant drop in market energy prices (for grid electricity or district heat) could negatively impact savings and extend the payback period. Cost Overruns: An increase in service (O&M) costs or higher-than-expected initial CAPEX. The project's economics are highly sensitive to these costs.
	Technical	Equipment Failure: Failure of key components, especially high-value items like heat pump compressors or PV inverters, leading to downtime and repair costs. Performance Risk: The system achieving a lower-than-expected real-world efficiency (e.g., seasonal COP) than simulated, reducing savings.
	Operational	Human Factor: The need to properly train the hospital's existing technical staff to manage and maintain the new, more complex hybrid system.
<u>BENEFITS</u>	Financial & Strategic	Cost Stabilization (Hedging): Acts as a long-term hedge against energy price volatility. It "freezes" the hospital's unit cost of heat at a stable, predictable level (e.g., 0.0908 EUR/kWh for V2) for 20 years, insulating the budget from market shocks. Operational Resilience: Stabilizes the hospital's operational costs for decades, which is a key strategic advantage for a public-sector entity.
	Energy Security	Supplier Independence: Creates significant independence from the municipal district heating network (MHPC) and volatile district heating prices. Variant 2 covers over 75% of heat demand. Grid Resilience: The combination of the PV installation and the 120 kWh energy storage system provides partial resilience to short-term grid power outages, enhancing operational continuity for a critical facility.
	Reputational (ESG/CSR)	Institutional Leadership: Positions the hospital as a leader in the energy transition and as an environmentally conscious institution. Stakeholder Relations: Serves as a positive communication tool for patients, staff, and the local community. Policy Alignment: The investment directly aligns with and supports national and EU climate policy goals, such as the European Green Deal.
	Environmental	CO ₂ Emissions Reduction: A direct and measurable contribution to combating climate change by significantly lowering the building's carbon footprint. Local Impact: Contributes to the improvement of air quality in Krakow, a city with known air pollution challenges.

The expanded Table 3 highlights the fundamental duality of this investment. On one hand, the project is exposed to significant market and regulatory risks, a fact confirmed by the sensitivity analysis. Changes to the net-billing system or volatility in energy prices are identified as having a high impact on profitability. While technical risks, such as equipment failure, are also present, they are more manageable. These can be mitigated through the selection of reputable suppliers and comprehensive service agreements, the cost of which (1.5% of CAPEX) has already been factored into the OPEX model.

On the other hand, the table clearly demonstrates that for a public-sector entity like a hospital, the non-financial and strategic benefits are critically important, potentially outweighing the purely financial metrics. The value of the project extends far beyond its positive NPV. Reputational (ESG) gains and alignment with EU climate policy (like the European Green Deal) strengthen the hospital's strategic position. Most importantly, in an era of increasing energy instability, the drastic improvement in energy security—achieved by gaining independence from a single district heating supplier (MHPC) and building resilience against grid outages—is a mission-critical advantage for a 24/7 healthcare facility.

Perhaps the most powerful strategic benefit quantified in the analysis is the "hedging" effect. The LCOH analysis proves that this investment effectively "freezes" the hospital's unit cost of heat at a stable, predictable level (e.g., 0.0908 EUR/kWh for the optimal Variant 2) for two decades. Given the forecasts for rising energy prices, this long-term budgetary stability and insulation from future price shocks provides immense, tangible value to the hospital, protecting its operational budget for years to come.

5. Comprehensive Economic Analysis and Lifecycle Profitability

5.1. Baseline Scenario (Variant 0—District Heating Network Only)

- Total heat demand: 107,319.86 kWh (HP) + 132,273.24 kWh (MHPC) = 239,593.10 kWh
- Annual cost: 239,593.10 kWh $\times$ 0.106 EUR/kWh = EUR 25,396.87

5.2. Operational Costs for the Modernization Variants (V1, V2, V3)

To facilitate a thorough economic analysis, Table 4 details the projected annual operational expenditures (OPEX) for each modernization variant. These estimates encompass all anticipated recurring costs (such as energy consumption, routine maintenance, and consumables) and serve as a key input for the comparative evaluation, supporting the assessment of total cost of ownership (TCO) and the ultimate decision-making process.

Table 4. Annual operational costs.

Cost/Revenue Item	Variant 1 (1 HP)	Variant 2 (2 HP)	Variant 3 (3 HP)
1. Cost of heat from district heating network (EUR)	14,005.81	6386.75	2183.62
2. Cost of grid electricity (EUR)	5310.25	9745.89	12,703.14
3. Revenue from PV energy sales (EUR)	20,000.15	19,434.37	19,075.77
4. Cost of service and maintenance (EUR)	3994.08	4359.31	4724.59
Annual OPEX (1 + 2–3 + 4) (EUR)	3310.00	1057.58	535.58

5.3. Profitability Indicators and Variant Comparison

Based on the calculated investment expenditures (CAPEX) and annual savings, the Simple Payback Time (SPBT) was determined (Table 5).

Table 5. CAPEX, annual savings, and SPBT.

Indicator	Variant 1 (1 HP)	Variant 2 (2 HP)	Variant 3 (3 HP)
Total CAPEX (EUR)	266,265.48	290,618.03	314,972.58
Annual savings (EUR)	22,086.87	24,339.29	24,861.29
Simple Payback Time (SPBT)	12.06 year	11.94 year	12.67 year
Heat demand coverage by HP	44.79%	74.97%	91.38%

Conducting a sensitivity analysis is crucial for assessing the project's robustness.

- Sensitivity to energy and heat prices: It is important to note that current forecasts indicate a further increase in the prices of both electricity (due to the cost of CO₂ emission allowances) and district heating (due to gas and coal prices). Paradoxically, a simultaneous increase in both of these prices will shorten the investment payback period. This is because the savings from avoiding the purchase of very expensive heat from MHPC will grow faster than the costs of purchasing electricity from the grid, the consumption of which is partially offset by self-generation from the PV installation. The system is therefore inherently resilient to a general increase in energy prices.
- Sensitivity to investment costs: The SPBT is directly proportional to the CAPEX. Potentially securing grants or preferential financing (e.g., from the National Fund for Environmental Protection and Water Management (NFOŚiGW) programs or EU funds [50,51]) could shorten the payback period to as little as 11–13 years, making the project attractive.
- Regulatory and technical risks: The most significant financial risk is a potential adverse change in the net-billing settlement system. The technical risk, on the other hand, is the possibility of failure of key components (the compressor in the HP, or the inverter in the PV system), which highlights the importance of choosing reputable suppliers and entering into long-term service agreements.

The modernization leads to a significant reduction in annual operational costs—by 87% in Variant 1 and as much as 98% in Variant 3. This is the result of replacing expensive heat from MHPC with much cheaper heat from the heat pumps, which are largely powered by free energy from the PV installation. Revenue from the sale of surplus energy further reduces the costs.

Variant 2 generates 10% higher savings than Variant 1. Adding the third heat pump (Variant 3) brings only a small, 2% increase in savings compared to Variant 2, which is disproportionate to the increase in investment expenditures. This phenomenon, known as the “law of diminishing returns”, clearly shows why Variant 2 achieves the shortest payback period (SPBT), representing the economic optimum.

5.4. Dynamic Lifecycle Profitability Analysis (NPV, LCC, AEC, LCOH)

In this chapter, we present an extended economic analysis for our project based on the Net Present Value (NPV), Annual Equivalent Cost (AEC), and Levelized Cost of Heating (LCOH) indicators.

To conduct the NPV and LCOH analysis, it is necessary to adopt the following assumptions:

- Project lifespan ($n = 20$ years): Selected to reflect the technical lifecycle of the main components. While PV panels often have a 25-year performance warranty, the operational lifespan of heat pumps in commercial applications is typically estimated at 15–20 years. A 20-year horizon provides a balanced approach for a hybrid system [25,26,53].
- Real discount rate ($r = 4\%$): This value aligns with the European Commission’s Guide to Cost–Benefit Analysis of Investment Projects, which recommends a social discount rate in the range of 3–5% for public infrastructure projects in Cohesion Countries, such as Poland. It reflects the lower risk profile of public healthcare facilities compared to private commercial investments.
- Real energy price escalation rate ($e = 2\%$): This represents a conservative forecast of the annual real price increase (above inflation). It accounts for the anticipated rise in electricity and district heating generation costs in Poland, driven primarily by the tightening EU Emissions Trading System (ETS) and the costs of energy transition.
- O&M Costs: Assumed to increase with inflation, and therefore their real escalation rate is 0%.

Given the inherent uncertainty of long-term forecasts, a sensitivity check was conducted within a scenario band of $r = 3\text{--}5\%$ and $e = 0\text{--}4\%$. The analysis confirms the stability of the results:

- Low-end scenario ($r = 5\%$, $e = 0\%$): Even with higher discounting and flat real energy prices, Variant 2 maintains a positive NPV, though the margin over Variant 1 narrows.
- High-end scenario ($r = 3\%$, $e = 4\%$): With aggressive price hikes and lower discounting, the NPV of all variants doubles, but Variant 2 remains the economic optimum. Variant 3 fails to overtake Variant 2 because the marginal cost of the third heat pump unit continues to exceed the marginal savings, regardless of the escalation rate.

5.4.1. Net Present Value (NPV)

NPV shows how much an investment is worth in today’s money, accounting for all future savings and costs over 20 years (Table 6). An $NPV > 0$ signifies a profitable investment. NPV was calculated as the sum of discounted savings (cash flows) minus the CAPEX.

$$NPV = PV_{\text{EnergySavings}} - PV_{\text{O\&M}} - CAPEX \quad (4)$$

where

- $PV_{\text{EnergySavings}}$ = Discounted savings from energy purchase (with 2% escalation).

- $PV_{O\&M}$ = Discounted maintenance costs (without escalation).
- CAPEX = Capital expenditure.

Table 6. NPV calculation for variants ($n = 20$ years, $r = 4\%$, and $e = 2\%$).

Indicator	Variant 1 (1 HP)	Variant 2 (2 HP)	Variant 3 (3 HP)
$PV_{EnergySavings}$ (EUR)	427,934	470,882	485,450
$PV_{O\&M}$ (EUR)	−54,279	−59,243	−64,213
CAPEX (EUR)	−266,265	−290,618	−314,973
NPV _(total) (EUR)	107,390	121,021	106,264

According to the fundamental principle of NPV analysis, an investment is profitable when its value is positive. The data shows that all three analyzed variants are profitable. Each of them generates a significant financial surplus over the initial costs, discounted to today's monetary value.

The savings increase with the size of the installation (the number of heat pumps), which is logical. Variant 3 generates the highest discounted savings (EUR 485,450). At the same time, the costs also increase. Variant 3 has the highest investment cost (CAPEX: EUR 314,973) and the highest discounted service costs (EUR 64,213).

The NPV analysis shows that the highest value is not achieved with maximum savings (Variant 3), but in Variant 2. This means that Variant 2 represents the optimal trade-off between the incurred outlays and the achieved benefits.

Variant 2 (2 HP) is the most profitable investment among all those considered. It generates the highest Net Present Value (NPV) at the level of EUR 121,021. This means that after accounting for the time value of money, 20-year costs, and savings, this investment will bring the investor the greatest financial benefit (approx. EUR 13.6k more than Variant 1 and approx. EUR 14.8k more than Variant 3).

5.4.2. Analysis of Annual Equivalent Cost (AEC) and Levelized Cost of Heat (LCOH)

LCOH is the most important comparative metric. It shows the real, averaged cost of producing 1 kWh of heat over the entire project lifecycle.

LCC (Lifecycle Cost):

$$LCC = CAPEX + PV_{totalOPEX} \quad (5)$$

AEC (Annual Equivalent Cost):

$$AEC = \frac{LCC}{\text{Annuity Factor}_{(r=4\%,n=20)}} \quad (6)$$

LCOH:

$$LCOH = \frac{AEC}{\text{Annual Heat Demand}} \quad (7)$$

The LCOH analysis unequivocally identifies Variant 2 as the economic optimum (Table 7.)

Table 7. Calculation of LCC, AEC, and LCOH for variants.

Indicator	Variant 0 (Base)	Variant 1 (1 HP)	Variant 2 (2 HP)	Variant 3 (3 HP)
CAPEX (EUR)	0	266,265	290,618	314,973
$PV_{TotalOPEX}$ (EUR)	416,718	43,056	5080	−4522 *
LCC_{Total} (EUR)	416,718	309,321	295,698	310,451
AEC (EUR)	30,663	22,760	21,758	22,844
LCOH (EUR/kWh)	0.1280	0.0950	0.0908	0.0953

* Variant 3 generates such high revenues from PV sales that its discounted operating costs over the life cycle are negative.

- Baseline Cost: The levelized cost of purchasing heat from MHPC over 20 years (with 2% escalation) is 0.1280 EUR/kWh.
- Optimal Variant: Variant 2 lowers this cost to 0.0908 EUR/kWh, “freezing” the cost of heat for the hospital at a level 29% lower than the projected baseline cost.
- Variant 3 (0.0953 EUR/kWh) is more expensive than Variant 2. Investing in the third heat pump is unprofitable because the capital cost (CAPEX) exceeds the additional operational savings.

5.4.3. Dynamic Analysis Summary

Variant 2 is the clear winner: the system model consisting of two heat pumps demonstrates the highest profitability across all key metrics:

- Shortest SPBT—11.94 years
- Highest NPV—EUR 121,021
- Lowest LCOH—0.0908 EUR/kWh

The NPV analysis unequivocally confirms that Variant 2 (two heat pumps) is the economically optimal choice. It provides the maximum added value for the investor (the highest NPV) over the 20-year time horizon, while simultaneously offering the lowest levelized costs (AEC and LCOH). This conclusion perfectly illustrates the phenomenon of diminishing returns, which becomes evident when comparing the successive variants. While moving from Variant 1 to Variant 2 (an additional CAPEX of approx. EUR 24.4k) yields an NPV increase of approx. EUR 13.6k, further increasing the investment to Variant 3 (another additional CAPEX of approx. EUR 24.4k) actually causes a decrease in the total NPV by approx. EUR 14.8k. This means that the additional savings generated by Variant 3 are no longer high enough to compensate for the significantly higher investment and service costs compared to Variant 2. Investing in the third heat pump is inefficient from the perspective of maximizing NPV. This finding is also confirmed by the other lifecycle indicators: Variant 2 proved to be the most favorable, demonstrating the lowest Annual Equivalent Cost (AEC = EUR 21,758) and the lowest Levelized Cost of Heating (LCOH = 0.0908 EUR/kWh).

It must be emphasized, however, that the high positive NPVs for all variants are strongly dependent on the adopted assumptions, especially the 2% energy price escalation (e). If energy prices did not increase (or increased more slowly), the discounted savings would be significantly lower, which would directly reduce the NPV, potentially making the investment less attractive. Despite this caveat, Variant 2 remains the undisputed optimum. Further scaling up the investment (Variant 3), while technically feasible, is already inefficient and leads to a decrease in profitability.

Table 8 below presents the key technical and economic parameters used in the analysis. The sensitivity ranking assesses the estimated impact of each parameter on the final outcome, particularly the Simple Payback Time (SPBT), where 1 indicates the highest sensitivity and 3 indicates the lowest.

Table 8. Sensitivity ranking.

Parameter	Value/Range	Source/Justification	Sensitivity Ranking
ECONOMIC PARAMETERS			
District Heat Price (MHPC)	0.105 EUR/kWh	Analysis of the MHPC business tariff for 2025.	1 (High)
Grid Electricity Purchase Price	0.212 EUR/kWh	Analysis of the Tauron B23 tariff for 2025.	1 (High)
PV Energy Sale Price	0.116 EUR/kWh	Projected market energy price (RCeM) in the net-billing system for 2025.	1 (High)

Table 8. *Cont.*

Parameter	Value/Range	Source/Justification	Sensitivity Ranking
Heat Pump Unit Cost	1 059 EUR/kW unit	Market analysis for commercial-grade units (Poland, 2025).	1 (High)
PV Installation Unit Cost	814 EUR/kWp	Market analysis for turnkey commercial installations (Poland, 2025).	1 (High)
Energy Storage Unit Cost	512 EUR/kWh	Market analysis (Poland, 2025).	1 (High)
SYSTEM PARAMETERS			
Heat Pump (HP) Nominal Power	20/40/60 kW	The design variable for the analyzed scenarios.	2 (Medium)
PV Installation Peak Power	180 kWp	Size based on the annual energy production from the simulation.	2 (Medium)
Energy Storage (ES) Capacity	120 kWh	Sized to optimize self-consumption.	2 (Medium)
Additional Costs (Hydraulics. Controls)	15% of primary costs	Engineering estimate based on the scope of work.	2 (Medium)
Service and Maintenance (O&M) Costs	1.5% of total CAPEX annually	Standard industry metric for energy systems.	2 (Medium)
SIMULATION PARAMETERS			
HP Performance Maps (COP. Power)	Matrix of values	Manufacturer's data for ambient temperatures of −7, 2, 7, and 12 °C, and outlet temperatures of 35/55 °C.	3 (Low)
Minimum Buffer Tank Temperature	35 °C	Control algorithm setpoint.	3 (Low)
Maximum Buffer Tank Temperature (with PV surplus)	50 °C	Control algorithm setpoint for storing surplus energy.	3 (Low)

As indicated in the Sensitivity Ranking (Table 8), economic indicators are highly sensitive to energy prices. However, a supplementary analysis confirms that minor fluctuations in the discount rate (± 1 p.p.) or escalation rate (± 1 p.p.) affect the absolute value of the NPV but do not change the final conclusion: Variant 2 remains the economic optimum due to the structural “law of diminishing returns” affecting the oversized Variant 3.

6. Results and Discussion

The results in 10 min time step are produced in a table exported as a csv or xls file. The specification values and their respective descriptions are presented in Table 9.

Table 9. Parameters used for control and as results in the simulated model.

Parameter Name	Parameter Type	Description
Ambient temperature	Controlling	Ambient air temperature based on meteorological data at a height of 2 m.
Global solar irradiation	Controlling	Global solar irradiance in the horizontal plane based on the meteorological data.
Building heat load	Result	Heat load of the building on the ambient air temperature.
Heat pump load	Result	Required load of the heat pump system, calculated based on the control algorithm.
Peak source heat load	Result	Power produced by the PV system, calculated based on the sun, DNI, and geometric sun height.
Heat pump energy use	Result	Electric energy use of the heat pump.
Heat pump COP value	Result	COP value for the heat pump, based on specification matrices and the parameters of ambient air temperature and heat pump heat sink temperature.
Buffer tank temperature	Result	Current temperature in the buffer tank at the beginning of the calculation period.

The model was set to produce results for 22 different parameters at each time step. The most important of them, covering both control variables (like ambient temperature) and key results (like heat pump load, instantaneous COP, or buffer temperature), are detailed in Table 8. The obtained aggregated annual results were then compared to the annual energy use calculated using the standard norm methodology, which is used for building energy certification. The analysis of these results was prepared for the main system variants (comprising one, two, or three heat pumps operating in parallel) and for an additional comparative variant, which featured two heat pumps set up in series.

The results provided in Table 10 show that adding an additional heat pump does not provide equivalent increase in heat production. A single unit provides 107,320 kWh of heat while adding a second unit increases this value by 73,383 kWh. A third unit causes an increase of only 37,888 kWh, providing a total share of 92% of the annual building load.

Table 10. Seasonal results of energy balance for all analyzed variants.

Variant	Total Provided Heat	Total Energy Provided by Heat Pump	PV Power Used for Heat Pump	Heat Pump Total Power Use	District Heating Power Use	Mean COP	Share of PV Power Used in Heat Pump	Share of Heat Produced by Heat Pump
		[kWh]	[kWh]	[kWh]	[kWh]	[-]	[%]	[%]
Single unit	239,593	107,320	9453	25,075	132,273	4.31	27.4	47
Two units	241,021	180,703	14,177	46,021	60,317	4.05	23.6	77
Two units in series	240,995	180,693	13,986	45,282	60,302	4.17	23.6	77
Three units	239,204	218,581	17,225	59,985	20,623	3.92	22.3	92

This effect is noticeable in the heat load graph (Figure 5). The increase in the provided heat load is not equivalent to the number of units. The higher the load, the rarer its occurrence, leading to only partial use of each additional heat pump unit. These results have an effect on economic feasibility of investment.

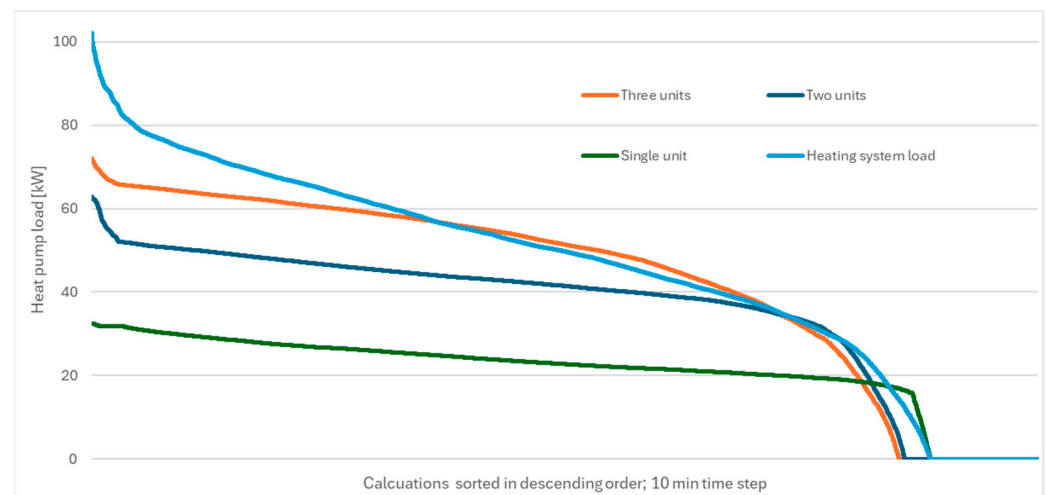


Figure 5. Sorted heat pump load in each analyzed variant.

It is noticeable that the total provided heat varies for each system. This variance is caused by heat losses in the buffered heat. Due to heat consumption being decoupled from production by buffered heat in the heating system, the small discrepancy is inevitable. However, the coefficient of variation for these values is equal to 0.39%, providing the results are not over varied.

The total heat demand of the building is equal to 239,000 kWh. The floor area of the hospital building is 2963 m². The specific heat demand of the building is 80.66 kWh/m².

It is noticeable that additional units cause the COP value to drop. This is caused by providing additional heat to the system and increasing the heated water temperature.

Adding an additional heat pump unit increases the temperature lift on heating system. This increase in temperature lift is the cause of the COP decrease. Another factor for this effect is the fact that more units provide heat in lower ambient temperatures, which also causes more worktime in conditions of higher temperature lift between the heat source and sink. The share of electric energy provided by the photovoltaic system also decreases with more heat pump units, due to the lack of coverage of heat load and sun irradiance.

The results of the series arrangement of the heat pump were not analyzed on the graph due to a small difference between use of two units in parallel or in series. The difference in mean COP value for the whole analyzed period was 2.85%, in favor of the series setting. The increase in efficiency is an effect of the fragmented temperature lift on the side of the heating system. Each unit provides only a part of the temperature lift, unlike the parallel set. The total decrease in energy consumption is even lower, reaching only 1.61%. From a techno-economic perspective, this marginal efficiency gain does not justify the increased complexity of the system. Implementing a series configuration would require more sophisticated hydraulic balancing and advanced control algorithms to synchronize the temperature lift across two units. Given that a significant portion of the energy consumed is self-generated by the PV system (lowering the effective unit cost of energy), the financial savings resulting from this 1.61% efficiency improvement are insufficient to cover the additional CAPEX and operational risks. Therefore, for this specific low-temperature application, the parallel configuration remains the preferred solution. The effect of the series setting is more important in high temperature heat pumps where the temperature lift is higher, or the decrease in the temperature of the heat source is an additional issue. In very high temperatures, the cycle has to be separated into different refrigerants requiring the series setting.

To maintain the international transferability of the findings, the baseline economic analysis assumes the project is fully funded by the investor without external subsidies. However, in the specific regulatory context of Poland, the project qualifies for the “Thermo-modernization Bonus” mentioned in the Introduction. Since the modernization includes the installation of Renewable Energy Sources (PV and Heat Pumps) constituting at least 10% of the total costs, the support level reaches 31% of the total CAPEX.

Applying this mechanism to the optimal Variant 2 yields the following impact:

- Net CAPEX reduction: The effective investment cost drops from EUR 290,618 to approximately EUR 200,526.
- Payback Period (SPBT) improvement: With the annual savings remaining constant at EUR 24,339, the Simple Payback Time decreases drastically from 11.94 years to 8.24 years.
- NPV increase: The reduced initial outlay would significantly boost the Net Present Value, making the investment highly attractive compared to standard financial instruments.

This demonstrates that while the project is defensible on purely market terms (approx. 12-year return), the utilization of available national support mechanisms transforms it into a high-yield investment with a return period of under a decade.

The consolidated Table 11 provides a powerful summary of the entire techno-economic analysis, clearly supporting the paper’s main conclusions:

- The table visually demonstrates that Variant 2 is the unequivocal optimal solution. It wins across all three key profitability metrics, achieving the shortest Simple Payback Time (SPBT), the highest Net Present Value (NPV), and the lowest Levelized Cost of Heating (LCOH).
- The table perfectly illustrates the law of diminishing returns, a key finding of the study. The move from Variant 2 to Variant 3 yields only a marginal increase in annual savings (approx. EUR 522) and heat coverage, but the higher CAPEX causes all

three profitability indicators (SPBT, NPV, and LCOH) to worsen. This confirms that Variant 3 is an inefficient, oversized investment.

- The table also reinforces the conclusion about the limitations of relying only on SPBT. While the SPBT for V1 (12.06 years) and V2 (11.94 years) appear very similar, the NPV analysis reveals the true, significant difference in long-term value, with Variant 2 generating over 12.7% more real value (EUR 121,021) than Variant 1 (EUR 107,390).

Table 11. Consolidated techno-economic comparison of all analyzed variants.

Metric	Variant 0 (Baseline)	Variant 1 (1 HP)	Variant 2 (2 HP)	Variant 3 (3 HP)	Source in Publication
Capital Expenditure (CAPEX)	EUR 0	EUR 266,265	EUR 290,618	EUR 314,973	Table 5
Annual Operating Costs (OPEX)	EUR 25,397	EUR 3310	EUR 1058	EUR 536	Table 4 Section 5.1
Annual Savings (vs V0)	-	EUR 22,087	EUR 24,339	EUR 24,861	Table 5
Heat Demand Coverage by HP	0%	44.79%	74.97%	91.38%	Table 5
Simple Payback Time (SPBT)	-	12.06 years	11.94 years	12.67 years	Table 5
Net Present Value (NPV)	-	EUR 107,390	EUR 121,021	EUR 106,264	Table 6
Levelized Cost of Heating (LCOH)	0.1280 EUR/kWh	0.0950 EUR/kWh	0.0908 EUR/kWh	0.0953 EUR/kWh	Table 7
Optimal Choice	-	-	✓	-	-

7. Conclusions

The techno-economic analysis of retrofitting a hospital heating system in Krakow confirms that transitioning from a district-heating-only model to a bivalent hybrid system is both economically viable and strategically necessary. Based on the high-resolution simulation and 2025 market data, the following key conclusions were drawn:

- Variant 2 (integrating 40 kW of heat pumps, 180 kWp PV, and 120 kWh energy storage) was identified as the undisputed optimal configuration. It achieves the highest Net Present Value (EUR 121,021), the lowest Levelized Cost of Heating (0.0908 EUR/kWh), and a Simple Payback Time of 11.94 years. This configuration reduces reliance on the district heating network by approximately 75%, maintaining it only as a necessary peak/backup source.
- The study proves that “bigger is not always better” for bivalent systems. While increasing capacity from 20 kW to 40 kW significantly boosted NPV, further expanding to 60 kW (Variant 3) resulted in value destruction, decreasing the NPV by over EUR 14,000. This confirms that covering the final peak loads with heat pumps is economically inefficient compared to utilizing the existing district heating connection. Beyond standard profitability, the system provides critical long-term price stability. The optimal variant “freezes” the cost of heat at 0.0908 EUR/kWh for 20 years, which is significantly lower than the projected baseline cost of district heat (0.1280 EUR/kWh). This acts as a hedge against future energy market volatility, a key advantage for public healthcare facilities.
- The analysis highlights the limitations of relying solely on the Simple Payback Time (SPBT) metric. SPBT suggested little difference between Variant 1 and Variant 2 (~12 years for both). However, the NPV analysis revealed that Variant 2 generates 12.7% more real value over the project lifecycle, proving that dynamic indicators are essential for correct sizing decisions in hybrid systems.

- A key element for the system's profitability is the maximization of the self-consumption of energy from the PV installation, which in the case of a facility with a 24/7 consumption profile, is made possible by use of an energy storage system.

The results indicate that for Polish hospitals, the optimal modernization pathway is not a complete disconnection from district heating, but a synergy where the DH network supports a correctly sized RES-based hybrid system. The obtained payback period (~12 years) is competitive compared to similar facilities in Europe and aligns with the operational stability required by the healthcare sector. Future work will expand this model to include cooling demand analysis and the optimization of energy storage control algorithms for spot-market electricity trading.

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