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Formulation of MILP models to assess the techno-economic impact of district heating electrification in energy communities ⋆

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ABSTRACT

Transitioning district heating in energy communities (ECs) from fossil-fuel to electrification requires advanced analytical tools for long-term assessment and informed decision-making. This paper proposes two novel mixed-integer linear programming models for a Finnish EC with diverse power-generating and storage units, with gas boiler and electric boiler configurations to promote sector-coupling. Both models are simulated over a year using operational data to compare operating costs, carbon emissions, and reliance on local renewable electricity generation. Results show that the electric boilers configuration significantly reduces emissions, lowers costs, and improves local renewable energy utilization, highlighting the benefits of electrifying ECs for future sustainability.

1. Introduction

In the current competitive industrial environment, there is a growing need to adopt sustainable, environmentally friendly operational practices, primarily driven by increasingly stringent regulations on greenhouse gas (GHG) emissions that affect human health, resource availability, and ecosystem stability (Bhatti et al. (2024)). The energy sector, in particular, is under scrutiny, as it accounts for more than 75% of global GHG emissions (Luca and Fransen (2020), U.S. Environmental Protection Agency (2023)). Unlike other industries, where GHG emission reduction strategies are often slow to implement due to limitations in modern tools and technologies, the energy sector has a significant potential to reduce emissions by replacing fossil-fueled systems with renewable energy-based resources. Consequently, it faces stricter regulations aimed at minimizing its carbon footprint (Safiullah et al. (2024)). Therefore, accelerating the implementation of decarbonization strategies in the energy sector is critical to reduce global GHG emissions and achieving carbon neutrality goals.

To achieve carbon neutrality in Europe, several measures have been taken, including upgrading outdated power generation systems and promoting the development of energy communities (ECs). ECs play a key role in the European Union's green transition by accelerating environmental, economic, and social objectives, such as reducing GHG emissions, enhancing energy efficiency, and providing energy to low-income and vulnerable populations (Blečić et al. (2025)). Furthermore, ECs support the transition from centralized energy production and distribution to a more decentralized system, reducing demand for large-scale energy systems while increasing system resilience and local autonomy. This transformation leads to improved system performance, lower consumer costs, and strengthened climate mitigation efforts. Reflecting their benefits, there are currently over 4500 ECs across Europe, with more than 100 located in Finland (Nordic Energy Research (2023), Uihlein and Caramizaru (2020)).

Finland aims to achieve carbon neutrality by 2035, necessitating a comprehensive transformation of its energy systems toward sustainable solutions. District heating (DH) accounts for more than one-third of the country's total energy production (International Energy Agency (2024)); therefore, many ECs in Finland still rely heavily on fossil-fuel-based combined heat and power (CHP) units and gas boilers (GB) to meet heating demands. These units typically operate on natural gas. Consequently, in 2024, more than 20% of heat energy is supplied from fossil-fuel-based units, contributing substantially to GHG emissions and hindering national climate objectives (Energy (2025)).

In Europe, gas prices have been highly volatile, driven mainly by supply uncertainties due to the expiration of the Russian gas transit agreement and large withdrawals from storage facilities (Fortum (2025)). On the other hand, market conditions are increasingly favorable to the electrification of DH systems. In 2024, Finland reported the highest number of negative electricity spot prices in Europe, with over 8% of the year hours characterized by very low or even zero-cost

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electricity (International Energy Agency (2024)). Furthermore, to encourage the electrification of DH systems, the Finnish government has reduced electricity taxation for heat pumps and electric boilers (EBs) (Hiltunen et al. (2025a)). Current regulations in Finland also allow ECs to prioritize locally generated electricity for their own consumption, including EBs operation (Finlex (2025)). On the contrary, to discourage fossil-fuel-based systems usage for heat generation, regulatory authorities are tightening GHG emission limits and increasing emission costs (Gugler et al. (2023)). Even if fossil fuel prices remain stable in the future, the growing emission prices make the continued operation of fossil-fuel-based systems such as GBs economically unviable (Mideksa (2024)). Given these current trends, the transition from fossil fuel-based systems to electrified alternatives offers ECs both economic and environmental benefits, supporting long-term sustainability.

To evaluate the feasibility and economic incentives of such a transition, ECs require advanced mathematical models capable of simulating diverse operational scenarios and assessing the techno-economic implications of shifting from conventional fossil-fuel systems to electrified alternatives. These models not only evaluate the economic and environmental impacts of the transition but also quantify operational flexibility, enabling economic gains and supporting informed investment decisions.

Several studies in the literature have examined the modeling and optimization of ECs comprising fossil fuel-based and electric DH systems, which align closely with the objectives of this work. Some studies developed optimization models for fossil-fuel-based DH systems (Saloux et al. (2023a)), while others proposed models for DH systems in large urban areas, analyzing the impact of EBs and heat storage on electricity prices, renewable curtailment, emissions, and fuel use (Hiltunen et al. (2025b)). Additionally, the operation of heat pumps and EBs in the Finnish balancing market has been investigated to assess their flexibility and economic potential (Javanshir et al. (2023)), and some works highlighted the feasibility of DH electrification in regions with high fossil-fuel generation due to rising fuel costs (Javanshir et al. (2022)). Most works have explored control and optimization approaches, including model predictive control (MPC), data-driven methods, and AI-based techniques for optimizing the operation of ECs (Saloux et al. (2023b), Tsoumalis et al. (2022)). Although these approaches are widely used in EC optimization, they differ fundamentally from the objective and modeling framework adopted in this work. MPC is well-suited for applications where control actions rely on real-time system states and continuously updated forecasts, making it effective for handling uncertainties and multi-step sequential decision-making (Abraham et al. (2023), Lim et al. (2025)). Data-driven and AI-based methods require large amounts of high-quality historical data for model development and are generally designed for operational control rather than for scenario-based techno-economic assessment (Elomari et al. (2024)). In contrast, this study employs a mixed-integer linear programming (MILP) approach, which enables the development of linear models of ECs to simulate different operational scenarios with guaranteed optimality. Since ECs typically involve discrete events, MILP can explicitly represent the discrete operation of ECs of different power-producing units, storage units, and sector-coupled interactions while maintaining tractability for day-ahead energy trading. These characteristics make MILP well aligned with the aims of this work, which focuses on comparative techno-economic evaluation rather than real-time control.

The models discussed in the literature offer valuable insights into the operation and optimization of ECs, having individual fossil-fuel-based systems or electrified setups in specific contexts. However, there remains a gap regarding models that address the transition from fossil-fuel DH systems to electrified alternatives within ECs that comprise diverse power generation and storage units and participate in external energy markets. To the best of the authors' knowledge, no existing study has examined electrified DH alternatives in ECs that enable sector coupling, exploit operational flexibility for the day-ahead electricity market, and provide comprehensive comparative analyses of operational costs, GHG emissions, and overall community performance. Furthermore, no existing model has been validated using real operational data over an extended period, such as a full year, to capture seasonal variations and fluctuations in energy prices. Therefore, there is a need for novel models that can address these challenges and be adapted for other ECs with similar generation portfolios and objectives.

This study builds upon our earlier work (Ahmed and Vilkko (2025a)) and extends its scope in several key directions, with the main contributions of the present work summarized as follows.

- Developing two novel MILP models that incorporate unit commitment and economic dispatch optimization concepts to capture the optimal turning on and off and power dispatch of units. The first model (Model 1) represents the baseline configuration with GBs, while the second (Model 2) explores an alternative configuration using EBs. Both models incorporate additional electrical and heat power-generation and energy storage units, enabling sector coupling and participation in the day-ahead electricity market.
- Comparing the operational performance of both models to provide actionable insights for EC stakeholders seeking strategies that balance climate targets with economic viability.
- Simulating both models for one year of operational data to examine the advantages and limitations of EBs in ECs; hence, this work contributes to a broader understanding of the role electrified DH can play in advancing sustainable energy transitions across Europe and beyond.

The paper is structured as follows. Section 2 introduces the EC considered in this paper, and Section 3 details the formulation of two models with distinct configurations. Section 4 presents the simulation results and analysis, and Section 5 concludes by summarizing the key findings and directions for future research.

2. Energy community

The EC considered in this study is LEMENE, a newly developed EC located in Lempäälä, Finland. Supported by the Finnish Ministry of Economic Affairs and Employment, LEMENE serves as a national pilot for smart and sustainable energy systems (Energia and Oy (2024)). This EC integrates fossil fuel-based CHP units and GBs for DH, fuel cells (FCs) and photovoltaic (PV) units for electricity generation, as well as batteries (ES) and heat storage (HS) systems. LEMENE is connected to the national grid, allowing it to trade electricity on the day-ahead market. Furthermore, all units are interconnected through a 20kV distribution grid operated by Elenia, with power exchanges subject to transmission fees. A schematic overview of the LEMENE is shown in Fig. 1.

2.1. Assumptions

This study is based on several assumptions, which include:

- All power generation and storage units are assumed to operate with constant operational efficiencies. In ECs, power-generating and storage units typically operate within relatively stable efficiency ranges under normal operating conditions; therefore, using constant efficiencies allows a fair comparison between the GB-based and EB-based EC configurations.
- ES and HS units have defined maximum and minimum capacity limits, and their initial inventory levels are chosen to provide a feasible starting point for the model. HS losses due to the body and other thermodynamic effects are neglected, as they have a minimal impact on the techno-economic assessment of both fossil-fuel-based and electrified configurations.
- LEMENE can participate in reserve markets for ancillary services in addition to day-ahead market operations. Although ES and EB systems provide operational flexibility, incorporating reserve market participation alongside day-ahead trading would introduce power activation uncertainties, impose strict availability requirements, and

continuous variables:

$\pi_i(\tau)$(MW)	Electrical power generated by unit i at time τ.
$\xi_i^{\kappa}(\tau)$(MW)	Electrical power exchanged between unit i and the smart grid in direction κ at time τ, where $\kappa \in$ [charge (in), discharge (out)].
$\theta_i(\tau)$(MW)	Heat power generated by unit i at time τ.
$\theta_i^{\delta}(\tau)$(MW)	Heat flow from unit i in direction δ at time τ, where $\delta \in$ [demand (dm), storage (hs)].
$\omega_i(\tau)$(MWh)	Energy stored in unit i at time τ.
$\Omega_i(\tau)$(MWh)	Energy loss from unit i at time τ.
$\phi^{\chi}(\tau)$(MWh)	Electricity traded in direction χ at time τ, where $\chi \in$ [sell, buy].
$\phi_{\beta}^{\text{buy}}(\tau)$(MWh)	Electricity bought is used for purpose β at time τ, where $\beta \in$ [charge ES (in), run EB (eb)].
$\phi_{\text{eb}}(\tau)$(MWh)	Total electrical power consumed by EBs at time τ.
$\mathcal{G}_i(\tau)$(MWh)	Fossil fuel consumed by unit i at time τ.
$\mathcal{P}(\tau)$(MW)	Electrical power generated at time τ.
$\mathcal{P}^{\text{local}}(\tau)$(MW)	Electrical power allocated for local use at time τ.
$\mathcal{P}_{\beta}^{\text{local}}(\tau)$(MW)	Electrical power that is produced and consumed locally for purpose β at time τ, where $\beta \in$ [charge ES (in), run EB (eb)].
$\mathcal{F}^{\text{run}}(\tau)(e)$	Total operating cost at time τ.
$\mathcal{F}^{\chi}(\tau)(e)$	Revenues or expenses associated with energy trading in direction χ at time τ.
$\mathcal{F}^{\text{line}}(\tau)(e)$	Transmission lines operating costs at time τ.

binary variables:

$\alpha_i(\tau)$	Activation status of unit i at time τ.
$\alpha_i^{\text{start}}(\tau)$	Start-up event of unit i at time τ.
$\alpha_i^{\delta}(\tau)$	Heat flow activation status of unit i in direction δ at time τ.

parameters:

Π_i^{up}(MW)	Maximum electrical power generating limit of unit i.
Π_i^{lo}(MW)	Minimum electrical power generating limit of unit i.
Θ_i^{up}(MW)	Maximum heat power generating limit of unit i.
Θ_i^{lo}(MW)	Minimum heat power generating limit of unit i.
$\mathcal{Q}_i^{\delta,\text{up}}$(MW)	Maximum heat flow in direction α.
$\mathcal{Q}_i^{\delta,\text{lo}}$(MW)	Minimum heat flow in direction α.
$\mathcal{E}_i^{\text{up}}$(MW)	Maximum allowable power transfer between storage unit i and smart grid.
$\mathcal{E}_i^{\text{lo}}$(MW)	Minimum allowable power transfer between storage unit i and smart grid.
$\mathcal{S}_i^{\text{up}}$(MWh)	Maximum energy that can be stored in unit i.
$\mathcal{S}_i^{\text{lo}}$(MWh)	Minimum energy that can be stored in unit i.
ϕ_{χ}^{up}(MWh)	Maximum energy trading limit in direction χ.
ϕ_{χ}^{lo}(MWh)	Minimum energy trading limit in direction χ.
$P_{\text{dm}}(\tau)$(MW)	Electrical power demand at time τ.
$\mathcal{Q}_{\text{dm}}(\tau)$(MW)	Heat power demand at time τ.
$\mathcal{V}(\tau)$(W/m^2)	Solar irradiance at time τ.
$\mathcal{W}_{\text{pv}}$(MWp)	Nominal peak power of PVs.
$C_i(\tau)(e/\text{MWh})$	Operating price of unit i.
$C_i^{\text{start}}(e/\text{MWh})$	Startup price of unit i.
$C^{\text{spot}}(\tau)(e/\text{MWh})$	Electricity spot price in the day-ahead market at time τ.
$C^{\text{line},\chi}(\tau)(e/\text{MWh})$	Transmission lines price associated with direction χ at time τ.
Υ_i(kg CO_2)	Carbon emission factor of unit i.
η_i^{elec}	Electrical efficiency of unit i.
η_i^{heat}	Thermal efficiency of unit i.

significantly increase computational complexity. Therefore, participation in reserve markets for ancillary services is excluded to maintain modeling tractability and focus on the techno-economic assessment of GB-to-EB transitions. Furthermore, it is assumed that LEMENE has the required infrastructure to participate in day-ahead trading and can flexibly meet its electrical power needs using locally generated or purchased electricity. Under current regulations, LEMENE can trade surplus energy only in the day-ahead market and is not permitted to sell electricity within the Lempäälä region (Power, 2023).

- The DH network does not store heat; therefore, heat demand must be met directly by HS, CHP units, or boilers, individually or in combination. The EC does not include any GHG capture technologies, and sufficient fossil fuels are assumed to be available for heat production.
- In this study, the simulation time interval is one hour. Since CHP and GB units typically require only a few minutes to start up or shut down, minimum up and down times are not considered in the model formulation.
- PV forecasts provided by LEMENE are assumed to be accurate, incorporating weather data such as temperature, solar radiation, and wind variations.
- In this study, historical electricity spot and gas prices are used, and the MILP models are formulated deterministically without considering uncertainties in market prices or heat demand. This choice is justified as the primary objective is not to design real-time dispatch strategies, where forecast errors and stochastic modeling would be critical. Instead, the goal is to perform a comparative techno-economic assessment of two different EC configurations under consistent market and load conditions. Such an assumption allows a transparent comparative techno-economic assessment, without the complexity introduced by stochastic modeling or forecast uncertainties.
- Transmission and local generation fees follow current regulations, and the smart grid is assumed capable of meeting all heat and electricity demands while controlling generation and storage units as needed.
- All input data are treated as deterministic, without the need for preprocessing or cleaning.

3. Models formulation

In this study, two distinct MILP models are formulated for LEMENE. The primary difference between these two models lies in the type of boilers used for heat generation and their interactions with the smart grid and the DH network.

In both models, τ denotes the time step ($\forall \tau \in \mathcal{T}$), and Γ^i represents the set of power-generating or energy storage unit i $\left(\forall i \in \left\{\Gamma^{\text{ES}}, \Gamma^{\text{CHP}}, \Gamma^{\text{FC}}, \Gamma^{\text{PV}}, \Gamma^{\text{GB}}, \Gamma^{\text{EB}}, \Gamma^{\text{HS}}\right\}\right)$.

3.1. Model 1 - LEMENE configuration with GBs

For electrical and heat generation units, their power output must operate within their respective upper and lower limits, as given in (1)

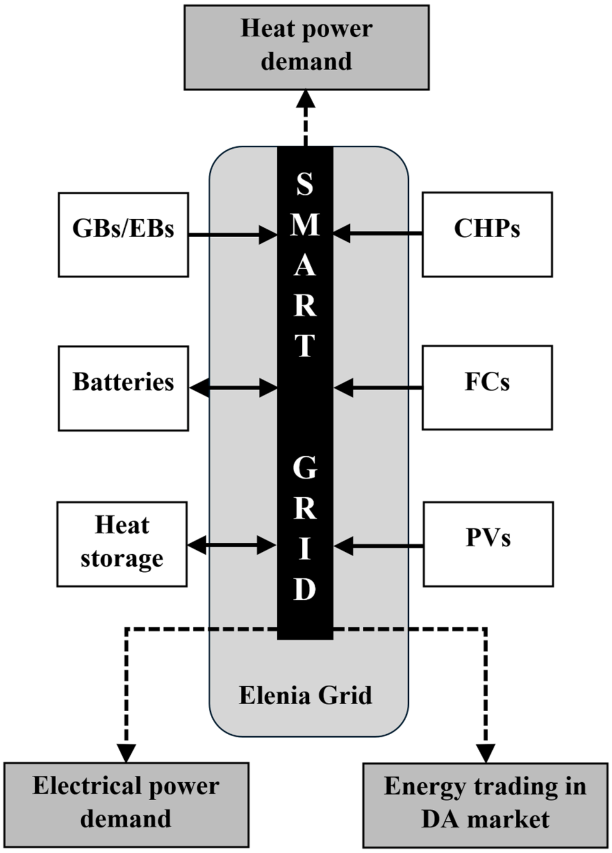

Fig. 1. LEMENE schematic diagram.

and (2). The operational status of each unit is governed by a binary variable $\alpha_i(\tau)$, which indicates whether the unit is active at time τ. For CHPs and GBs, electrical and heat power depend on their respective unit efficiencies η_i^{elec} and η_i^{heat}, as presented in (3) and (4).

$$\Pi_i^{\text{lo}}\alpha_i(\tau) \leq \pi_i(\tau) \leq \alpha_i(\tau)\Pi_i^{\text{up}} \quad \forall\tau \in \mathcal{T}, i \in \{\Gamma^{\text{CHP}}, \Gamma^{\text{FC}}, \Gamma^{\text{PV}}\} \tag{1}$$

$$\Theta_i^{\text{lo}}\alpha_i(\tau) \leq \theta_i(\tau) \leq \alpha_i(\tau)\Theta_i^{\text{up}} \quad \forall\tau \in \mathcal{T}, i \in \{\Gamma^{\text{CHP}}, \Gamma^{\text{GB}}\} \tag{2}$$

$$\pi_i(\tau) \leq \eta_i^{\text{elec}}\frac{\mathcal{G}_i(\tau)}{\Delta\tau} \quad \forall\tau \in \mathcal{T}, i \in \Gamma^{\text{CHP}} \tag{3}$$

$$\theta_i(\tau) \leq \eta_i^{\text{heat}}\frac{\mathcal{G}_i(\tau)}{\Delta\tau} \quad \forall\tau \in \mathcal{T}, i \in \{\Gamma^{\text{CHP}}, \Gamma^{\text{GB}}\} \tag{4}$$

In ECs, PV power forecasts are typically estimated using modern sensors and remote-sensing technologies. When such sensors are unavailable, it can be estimated using the available solar irradiance $\mathcal{V}(\tau)$ and the nominal peak power of the PV system $\mathcal{W}_{\text{pv}}$.

$$\pi_i(\tau) = \mathcal{V}(\tau)\mathcal{W}_{\text{pv}} \quad \forall\tau \in \mathcal{T}, i \in \Gamma^{\text{PV}} \tag{5}$$

The heat produced by the CHP and GB units is either stored in the HS for later use or is used to meet the demands. Therefore, at each time step τ, the heat produced by these units must be equal to the sum of the heat directed to the heat storage $\theta_i^{\text{hs}}(\tau)$ and the heat supplied to meet the demand $\theta_i^{\text{dm}}(\tau)$, as given in (6). A binary variable $\alpha_i^{\delta}(\tau)$ is used to indicate the activation of heat flow in each respective direction, as indicated in (7). The heat flow in either direction is constrained by the minimum and maximum limits.

$$\theta_i(\tau) = \theta_i^{\text{hs}}(\tau) + \theta_i^{\text{dm}}(\tau) \quad \forall\tau \in \mathcal{T}, i \in \{\Gamma^{\text{CHP}}, \Gamma^{\text{GB}}\} \tag{6}$$

$$\mathcal{Q}_i^{\delta,\text{lo}}\alpha_i^{\delta}(\tau) \leq \theta_i^{\delta}(\tau) \leq \alpha_i^{\delta}(\tau)\mathcal{Q}_i^{\delta,\text{up}} \quad \forall\tau \in \mathcal{T}, i' \in \{\Gamma^{\text{CHP}}, \Gamma^{\text{GB}}\}, \delta \in \{\text{hs}, \text{dm}\} \tag{7}$$

The heat discharged from the HS, $\theta_i^{\text{dm}}(\tau)$, can be used to meet the demand. Therefore, this heat flow is also subject to its maximum and minimum flow limits, as given in (8).

$$\mathcal{Q}_i^{\text{dm,lo}}(\tau) \leq \theta_i^{\text{dm}}(\tau) \leq \mathcal{Q}_i^{\text{dm,up}}(\tau) \quad \forall\tau \in \mathcal{T}, i \in \Gamma^{\text{HS}} \tag{8}$$

The energy level in the ES and HS units, denoted by $\omega_i(\tau)$, is determined by their previous state, the charging and discharging power, and is subject to losses arising from the limited efficiency η_i during charging and discharging operations, as given in (9) and (10). ES units can be charged either with locally generated electricity or with the electricity procured from the day-ahead market. Similarly, it can discharge power to the smart grid for local use to meet the demand or sell it in the day-ahead market. Due to the technical limitations, the total power exchanged between the ES units and the smart grid must remain within the predefined operational limits, denoted by $\mathcal{E}_i^{\text{up}}(\tau)$ and $\mathcal{E}_i^{\text{lo}}(\tau)$, as given in (11). In contrast, the HS is charged using heat generated by the CHP and GB units, while its discharged heat is used to satisfy the heat demand, either alone or in combination with the heat produced by the CHP and GB units.

$$\omega_i(\tau) = \omega_i(\tau-1) + \Delta\tau\left(\eta_i\xi_i^{\kappa}(\tau) - \frac{\xi_i^{\kappa'}(\tau)}{\eta_i}\right) \quad \forall\tau \in \mathcal{T}, i' \in \Gamma^{\text{ES}}, \kappa \in \text{in}, \kappa' \in \text{out} \tag{9}$$

$$\omega_i(\tau) = \omega_i(\tau-1) + \Delta\tau\left(\eta_i\theta_i^{\delta}(\tau) - \frac{\theta_i^{\delta'}(\tau)}{\eta_i}\right) \quad \forall\tau \in \mathcal{T}, i \in \Gamma^{\text{HS}}, i' \in \{\Gamma^{\text{CHP}}, \Gamma^{\text{GB}}\}, \delta \in \text{hs}, \delta' \in \text{dm} \tag{10}$$

$$\mathcal{E}_i^{\text{up}}(\tau) \leq \xi_i^{\kappa}(\tau) \leq \mathcal{E}_i^{\text{lo}}(\tau) \quad \forall\tau \in \mathcal{T}, i \in \Gamma^{\text{ES}}, \kappa \in \{\text{in}, \text{out}\} \tag{11}$$

For ES and HS units, the operational losses $\Omega_i(\tau)$ during charging and discharging operations are calculated using (12) and (13). This study accounts for losses associated with charging and discharging operations and does not include losses arising from the thermodynamic properties of the storage units.

$$\Omega_i(\tau) = \Delta\tau(1-\eta_i)\xi_i^{\kappa}(\tau) + \Delta\tau(\frac{1}{\eta_i}-1)\xi_i^{\kappa'}(\tau) \quad \forall\tau \in \mathcal{T}, i' \in \Gamma^{\text{ES}}, \kappa \in \text{in}, \kappa' \in \text{out} \tag{12}$$

$$\Omega_i(\tau) = \Delta\tau(1-\eta_i)\theta_i^{\delta}(\tau) + \Delta\tau(\frac{1}{\eta_i}-1)\theta_i^{\delta'}(\tau) \quad \forall\tau \in \mathcal{T}, i \in \Gamma^{\text{HS}}, i' \in \{\Gamma^{\text{CHP}}, \Gamma^{\text{GB}}\}, \delta \in \text{hs}, \delta' \in \text{dm} \tag{13}$$

To ensure continuity and cyclic operation, the final energy state of storage units at the end of the horizon T must equal their initial state, which prevents the model from perpetually draining or overfilling storage, as presented in (14). Additionally, the energy level of all storage units must always remain within their defined minimum and maximum limits, as given in (15).

$$\omega_i(T) = \omega_i(0) \quad i \in \{\Gamma^{\text{ES}}, \Gamma^{\text{HS}}\} \tag{14}$$

$$\mathcal{S}_i^{\text{lo}} \leq \omega_i(\tau) \leq \mathcal{S}_i^{\text{up}} \quad \forall\tau \in \mathcal{T}, i \in \{\Gamma^{\text{ES}}, \Gamma^{\text{HS}}\} \tag{15}$$

For units that consume fossil fuels, such as CHP and GB units, frequent startups should be avoided, as they reduce the lifespan of units and increase maintenance costs (Beis (2021)). Therefore, the on/off commitment of these units is explicitly modeled. Startups o these are captured by the binary variable $\alpha_i^{\text{start}}(\tau)$, which is determined from the unit operational state $\alpha_i(\tau)$. This variable takes a value of 1 only when a unit switches from an off state in the previous time step to an on state in the current time step; otherwise, it remains zero, as defined in (16).

$$\alpha_i^{\text{start}}(\tau) \geq \alpha_i(\tau) - \alpha_i(\tau-1) \quad \forall\tau \in \mathcal{T}, i \in \{\Gamma^{\text{CHP}}, \Gamma^{\text{GB}}\} \tag{16}$$

LEMENE can trade electricity in the day-ahead market. However, due to the limitations of the transmission lines owned by Elenia, this exchange is constrained by the available transmission capacity, represented by the upper and lower bounds ($\phi_{\chi}^{\rm up}, \phi_{\chi}^{\rm lo}$), as given in (17).

$$\phi_{\chi}^{\rm lo} \leq \frac{\phi^{\chi}(\tau)}{\Delta\tau} \leq \phi_{\chi}^{\rm up} \quad \forall \tau \in \mathcal{T}, \chi \in \{\text{buy}, \text{sell}\} \tag{17}$$

The total available power in the LEMENE, $\mathcal{P}(\tau)$, is defined as the combined output from CHPs, PVs, FCs, and ES units and power purchased from the day-ahead market when local generation is insufficient to meet demand or when it is more economical to procure electricity, as represented by the term $\frac{\phi^{\rm buy}(\tau)}{\Delta\tau}$ in (18). Let

$\Gamma^{\rm elec} = \{\Gamma^{\rm CHP}, \Gamma^{\rm FC}, \Gamma^{\rm PV}\}$

$$\mathcal{P}(\tau) = \sum_{i\in\Gamma^{\rm elec}} \pi_i(\tau) + \sum_{i\in\Gamma^{\rm ES}} \xi_i^{\rm out}(\tau) + \frac{\phi^{\rm buy}(\tau)}{\Delta\tau} \quad \forall \tau \in \mathcal{T} \tag{18}$$

The available power $\mathcal{P}(\tau)$ must balance with the power allocated to day-ahead market sales $\frac{\phi^{\rm sell}(\tau)}{\Delta\tau}$, local demand $P_{\rm dm}(\tau)$, and local consumption $\mathcal{P}^{\rm local}(\tau)$, as enforced through time-coupled balance constraint in (19), which ensures that supply meets demand at every time step.

$$\mathcal{P}(\tau) = \frac{\phi^{\rm sell}(\tau)}{\Delta\tau} + P_{\rm dm}(\tau) + \mathcal{P}^{\rm local} \quad \forall \tau \in \mathcal{T} \tag{19}$$

LEMENE must satisfy the heat demand $Q_{\rm dm}(\tau)$, which is enforced by the time-coupled balance constraint in (20) to ensure that heat allocated by the CHPs, GBs, and HS unit to meet the demand is always fulfilled. Let

$\Gamma^{\rm fossil} = \{\Gamma^{\rm CHP}, \Gamma^{\rm GB}\}$

$$\sum_{i\in\Gamma^{\rm fossil}} \theta_i^{\rm dm}(\tau) + \sum_{i\in\Gamma^{\rm HA}} \theta_i^{\rm dm}(\tau) = Q_{\rm dm}(\tau) \quad \forall \tau \in \mathcal{T} \tag{20}$$

For LEMENE configuration with GBs, the purchased electricity ($\phi^{\rm buy}(\tau)$) can be used either to meet demand or for the local use, as defined in (18) and (19). Here, the local use referts only to charge the ES units ($\xi_i^{\rm in}(\tau)$), as given in (21). This flexibility enables LEMENE to purchase electricity during low-price periods and rely on local generation when prices are high or buying from day-ahead market is uneconomical.

$$\sum_{i\in\Gamma^{\rm ES}} \xi_i^{\rm in}(\tau) = \mathcal{P}^{\rm local}(\tau) \quad \forall \tau \in \mathcal{T} \tag{21}$$

For Model 1, the total operating costs include costs ($C_i(\tau)$ in e/MWh) associated with electricity and heat generation, as well as losses arising from storage unit inefficiencies, as given in (22). Minimizing these losses discourages simultaneous charging and discharging, thereby reducing the number of binary variables in the model formulation. For CHP and GB units, additional startup costs ($C_i^{\rm start}$ in e) are incurred when these units transition from an off state to an operational state. Furthermore, the model accounts for the expenses or revenue associated with energy trading ($C^{\rm spot}(\tau)$ in e/MWh), along with the total transmission costs for the Elenia network for power flow in direction χ ($C^{{\rm line},\chi}(\tau)$ in e/MWh), as given in (23) and (24). Let

$\Gamma^{\rm renew} = \{\Gamma^{\rm FC}, \Gamma^{\rm PV}\}$, $\Gamma^{\rm stg} = \{\Gamma^{\rm ES}, \Gamma^{\rm HS}\}$

$$\begin{aligned}\mathcal{F}^{\rm run}(\tau) = &\sum_{i\in\Gamma^{\rm fossil}} [C_i(\tau)\mathcal{G}_i(\tau) + C_i^{\rm start}\alpha_i^{\rm start}(\tau)] + \sum_{i\in\Gamma^{\rm renew}} \Delta\tau C_i(\tau)\pi_i(\tau) \\ &+ \sum_{i\in\Gamma^{\rm stg}} C_i(\tau)\Omega_i(\tau) \quad \forall \tau \in \mathcal{T}\end{aligned} \tag{22}$$

$$\mathcal{F}^{\chi}(\tau) = C^{\rm spot}(\tau)\phi^{\chi}(\tau) \quad \forall \tau \in \mathcal{T}, \chi \in \{\text{buy}, \text{sell}\} \tag{23}$$

$$\begin{aligned}\mathcal{F}^{\rm line}(\tau) = &C^{\rm line,buy}(\tau)[P_{\rm dm}(\tau) + \mathcal{P}^{\rm local}(\tau) + \\ &(\tau)\phi^{\rm buy}(\tau)] + C^{\rm line,sell}(\tau)\phi^{\rm sell}(\tau) \quad \forall \tau \in \mathcal{T}\end{aligned} \tag{24}$$

The objective of LEMENE is to minimize the overall operating costs of all electrical and heat-generating units and storage systems, the transmission costs associated with the Elenia grid operator, and electricity purchases in the day-ahead market, while maximizing revenue from the day-ahead market, as formulated in (25).

$$\min \quad \mathcal{F}^{\rm run}(\tau) + \mathcal{F}^{\rm Line}(\tau) + \mathcal{F}^{\rm buy}(\tau) - \mathcal{F}^{\rm sell}(\tau) \tag{25}$$

3.2. Model 2 - LEMENE configuration with EBs

Model 2 is derived from Model 1, with modifications to the constraints governing the operation of GBs. It employs EBs instead of GBs, operating with either purchased or locally generated electricity. Consequently, the set $\Gamma^{\rm GB}$ is replaced with $\Gamma^{\rm EB}$ in (2), (6)-(7), (10), and (13). Additionally, several constraints are revised to reflect the operational characteristics of the EB. In particular, (4) is reformulated to account for electricity as the energy input and is replaced by (26) and (27).

$$\theta_i(\tau) \leq \eta_i^{\rm heat} \frac{\mathcal{G}_i(\tau)}{\Delta\tau} \quad \forall \tau \in \mathcal{T}, i \in \Gamma^{\rm CHP} \tag{26}$$

$$\theta_i(\tau) \leq \eta_i^{\rm heat} \frac{\phi_{\rm eb}(\tau)}{\Delta\tau} \quad \forall \tau \in \mathcal{T}, i \in \Gamma^{\rm GB} \tag{27}$$

Unlike GBs, EBs do not involve a combustion process, allowing a rapid response time and resulting in minimal or near-zero costs associated with the startup, in contrast to fuel-based GBs. Therefore, (16) is modified to account only for the frequent startups costs associated with the CHP units, which is given in (28).

$$\alpha_i^{\rm start}(\tau) \geq \alpha_i(\tau) - \alpha_i(\tau - 1) \quad \forall \tau \in \mathcal{T}, \forall i \in \Gamma^{\rm CHP} \tag{28}$$

EBs can be operated using electricity purchased from the day-ahead market or local electricity generated by the LEMENE. Therefore, the purchased electricity from the day-ahead market, $\phi^{\rm buy}(\tau)$, and power allocated for the local use, $\mathcal{P}^{\rm local}(\tau)$, in Model 2 can be used either to charge the ES units or to supply power to the EBs, as expressed in (29) and (30).

$$\phi^{\rm buy}(\tau) = \phi_{\rm in}^{\rm buy}(\tau) + \phi_{\rm eb}^{\rm buy}(\tau) \quad \forall \tau \in \mathcal{T} \tag{29}$$

$$\mathcal{P}^{\rm local}(\tau) = \mathcal{P}_{\rm in}^{\rm local}(\tau) + \mathcal{P}_{\rm eb}^{\rm local}(\tau) \quad \forall \tau \in \mathcal{T} \tag{30}$$

Unlike Model 1, in Model 2, both the ES and EBs can utilize electricity purchased from the day-ahead market. Consequently, (21) is modified to account for these changes and is presented as (31). Additionally, the total electricity required to operate the EBs is determined using (32).

$$\sum_{i\in\Gamma^{\rm ES}} \xi_i^{\rm in}(\tau) = \frac{\phi_{\rm in}^{\rm buy}(\tau)}{\Delta\tau} + \mathcal{P}_{\rm in}^{\rm local}(\tau) \quad \forall \tau \in \mathcal{T} \tag{31}$$

$$\phi_{\rm eb}(\tau) = \phi_{\rm eb}^{\rm buy}(\tau) + \Delta\tau\mathcal{P}_{\rm eb}^{\rm local}(\tau) \quad \forall \tau \in \mathcal{T} \tag{32}$$

The operating costs of the EBs include the cost of electricity they consume during operation. Therefore, the total operating cost, as presented in (22), is modified as expressed in (33), while the objective remains the same, as presented in (25).

$$\begin{aligned}\mathcal{F}^{\rm run}(\tau) = &\sum_{i\in\Gamma^{\rm CHP}} [C_i(\tau)\mathcal{G}_i(\tau) + C_i^{\rm start}\alpha_i^{\rm start}(\tau)] + \sum_{i\in\Gamma^{\rm EB}} C^{\rm spot}(\tau)\phi_{\rm eb}^{\rm buy}(\tau) \\ &+ \sum_{i\in\Gamma^{\rm renew}} \Delta\tau C_i(\tau)\pi_i(\tau) + \sum_{i\in\Gamma^{\rm stg}} C_i(\tau)\Omega_i(\tau) \quad \forall \tau \in \mathcal{T}\end{aligned} \tag{33}$$

4. Simulation setup

Both models are simulated for each month over a full calendar year with a time interval of 1 h ($\Delta\tau = 1$). The number of hourly intervals per month varies with the number of days, resulting in 672, 720, or 744 time steps per simulation. The simulation period (June 2024 to May 2025) is selected to capture seasonal variations in heat demand in Finland as well as fluctuations in electricity spot prices. It also corresponds to the most recent available historical data, ensuring that the simulations reflect realistic and up-to-date operating conditions. CHP units are assumed to operate at an overall efficiency of 90%, with equal electrical and thermal efficiencies of 45% each, and GBs and EBs are modeled with efficiencies of 90% and 95%, respectively. Furthermore, LEMENE requires approximately 250 kW of electrical power to operate its on-site systems, a demand that remains mostly constant throughout the year.

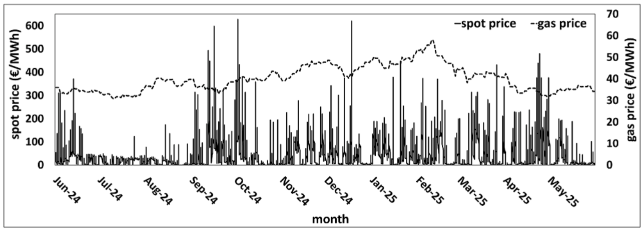

Fig. 2. Electricity spot and gas prices.

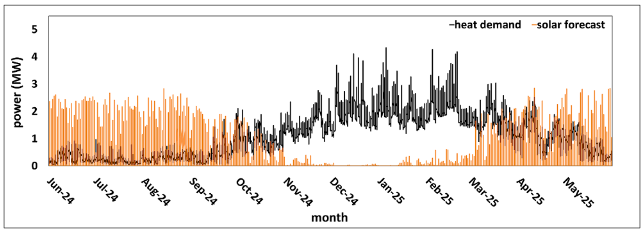

Fig. 3. Heat demand and solar forecast.

Table 1
Model parameters.

Parameter	Unit						
	CHPs	GBs	EBs	FCs	PVs	ESs	HS
Π_i^{up} (MW)	8.1	–	–	0.0165	4	–	–
Π_i^{lo} (MW)	0.1	–	–	0.01	0	–	–
Θ_i^{up} (MW)	7.01	7	7	–	–	–	–
Θ_i^{lo} (MW)	0.1	0.1	0.1	–	–	–	–
$\mathcal{Q}_i^{\delta,up}$ (MW)	5	5	5	–	–	–	3
$\mathcal{Q}_i^{\delta,lo}$ (MW)	0.01	0.01	0.01	–	–	–	0.01
$\mathcal{E}_i^{up}$ (MW)	–	–	–	–	–	4	–
$\mathcal{E}_i^{lo}$ (MW)	–	–	–	–	–	0	–
$\mathcal{S}_i^{up}$ (MWh)	–	–	–	–	–	3.6	25
$\mathcal{S}_i^{lo}$ (MWh)	–	–	–	–	–	0.02	0.5

Given its relatively low magnitude, this demand is excluded from further analysis.

In all simulations, electricity spot prices are obtained from Pörssisähkö, while natural gas prices are taken from the Dutch TTF gas market (Endex, 2025; Pörssisähkö & Net, 2024), as illustrated in Fig. 2. Solar power output forecasts and heat demand are obtained directly from the LEMENE database, as shown in Fig. 3. The LEMENE is connected to the Elenia distribution grid, which imposes capacity limits of 10 MW for electricity purchases ($\phi_{buy}^{up} = 10$) and 4 MW for electricity sales ($\phi_{sell}^{up} = 4$) and lower limits are set to zero. Transmission costs for Elenia are 16.44 e/MWh for purchased electricity ($C^{line,buy}(\tau) = 16.44$) and 0.7 e/MWh for electricity sold or distributed locally ($C^{line,sell}(\tau) = 0.7$) (Oy, 2025). The CO_2 emission factor for both CHP units and GBs is 200.92 kg/MWh, while FCs' operating cost is assumed to be 150 e/MWh with an efficiency of 90% (Tilastokeskus, 2023; Zhou & Searle, 2022). The total carbon emissions are calculated using (34). Energy loss costs are set at 20 e/MWh. A complete overview of all model parameters is provided in Table 1.

$$\text{emission}(\tau) = \mathcal{G}_i(\tau)\Upsilon_i \quad \forall \tau \in \mathcal{T} \tag{34}$$

Both models are simulated 12 times each, corresponding to each month of the year. In each simulation, all input data are treated as deterministic, and the corresponding MILP problem is solved on the same computing machine. All simulations are initialized with identical initial conditions and the simulation environment, including model parameters, operational constraints, and market conditions, remains unchanged throughout all simulations.

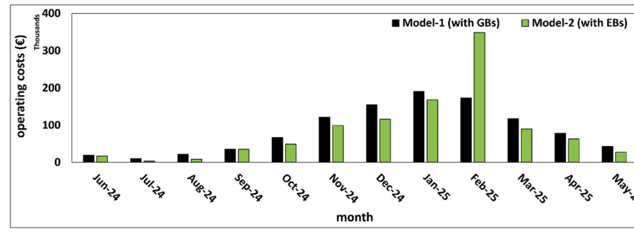

Fig. 4. Operating costs.

5. Simulation results

For both models, Figs. 4–6 present monthly operating costs and day-ahead trading revenues and expenses. Model 2 (EB configuration) achieves lower operating costs than Model 1 (GB configuration) for most months. For instance, in July, operating costs for Model 2 drop to less than one-third of those for Model 1, and even during peak-demand months such as December and January, Model 2 maintains a cost advantage. This advantage is due to Model2׳s greater flexibility in utilizing locally generated electricity from ES, PV, and CHP units, whereas Model 1 relies solely on natural gas, whose costs are inflexible.

Model 2 exhibits an exception in February, when its operating costs are higher compared to Model 1 due to peak heat demand coinciding with high electricity spot prices. Although heat demand and electricity spot prices are also high in December and January, the disproportionately higher operating cost in February results from the combined effects of high electricity spot prices and limited on-site electricity generation. In February, a larger portion of the heat demand coincides with consecutive high electricity spot price hours, at a time when on-site generation is insufficient. Although electricity spot prices are comparably high in December and January, peak heat demand overlaps less with high-price periods than in February. In addition, higher gas prices in February make gas-based heat production less attractive, resulting in increased electricity purchases during high spot-price hours. This interaction between gas price profiles, demand timing, and electricity spot price fluctuations explains why February exhibits higher operating costs despite similar nominal heat demand and electricity spot price levels earlier in the winter.

Profitability analysis of energy trading indicates that while both models benefit from seasonal electricity price fluctuations, Model 2 generates slightly lower revenues than Model 1 due to reduced day-ahead market sales, as a portion of the CHP output is allocated to operate EBs, as shown in Fig. 5. Nevertheless, Model 2 provides greater operational flexibility, particularly during low-price summer periods such as July and August, by increasing electricity purchases and thereby reducing overall operating costs, as illustrated in Figs. 4 and 6. In addition, Model 2 substantially improves local electricity utilization, increasing it by three to four times compared to Model 1 in some months (e.g., May: 274 MWh versus 87 MWh), strengthening LEMENE's self-sufficiency, and mitigating exposure to market volatility, as shown in Fig. 7. Although this strategy results in higher transmission charges to Elenia, these costs can be offset or eliminated through investments in LEMENE-owned transmission infrastructure in the future, thereby reinforcing the long-term economic viability of DH electrification.

In terms of emissions, Model 2 substantially reduces the carbon footprint, particularly during peak winter months, as shown in Fig. 8. For example, in February, although Model 2 incurs higher operating costs, carbon emissions decrease by more than 6% compared to Model 1. This demonstrates its potential to leverage electricity from local renewable sources and contribute to further decarbonization of the smart grid. Despite the higher operating costs in February, the rising allowance prices (CO_2 emission price) in the EU ETS (European Commission (2005)) incentivize the adoption of EBs in LEMENE, particularly in light of tightening emission regulations across Europe.

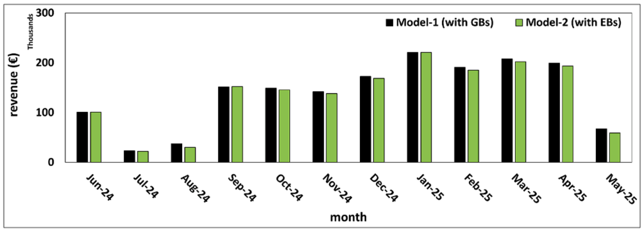

Fig. 5. Revenues from day-ahead trading.

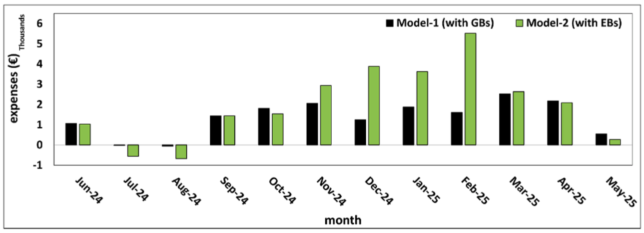

Fig. 6. Expenses from day-ahead trading.

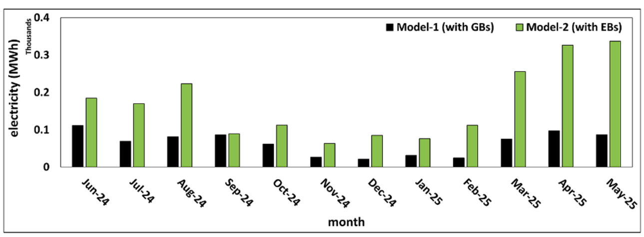

Fig. 7. Local electricity utilization.

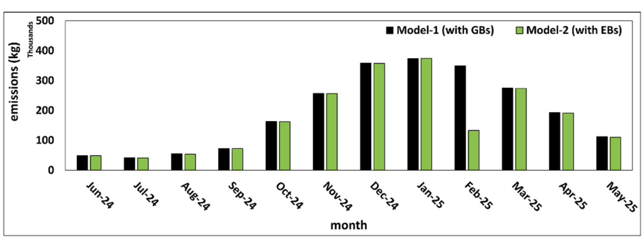

Fig. 8. Carbon emissions.

Table 2 presents a comparison of total annual costs, emissions, and local electricity utilization. Although Model 2 shows a slightly higher annual operating cost (about 0.47%), primarily due to a larger portion of the heat demand coinciding with consecutive high electricity spot price hours in February, this increase is offset by substantial environmental and operational benefits. Carbon emissions are reduced by nearly 10%, reflecting the enhanced integration of on-site renewable generation and more efficient EBs operation, particularly during periods of high demand. The most pronounced improvement is in local energy utilization, which more than doubles in Model 2, enhancing self-sufficiency and reducing reliance on external electricity markets. It should be noted that Model 2 inherently consumes more locally produced electricity; comparison with Model 1 is justified because both models are evaluated under identical system conditions, input data, and market rules, allowing a fair assessment of the economic and environmental impact of transitioning from fossil-fuel-based boilers to electrified alternatives. These findings demonstrate that EBs not only contribute to emission reductions but also enhance economic efficiency and renewable units integration, making them a future-proof solution for LEMENE and other Nordic ECs.

Both models are solved using Gurobi 11.0 and an optimality gap of 1e-2. Since both models are simulated for all months in a calendar year,

Table 2
Annual performance metrics.

Indicator	Model 1	Model 2	Diff.
Costs (10^3 EUR)	1051.1	1056.1	+0.47%
Emissions (10^3 kg)	2297.5	2075.2	-9.7%
Local use (MWh)	775.1	2038.3	+163%

the number of variables varies with the number of time steps. Depending on the simulation month, Model 1 contains 18120-20064 continuous variables, 17693-19864 discrete variables, and 34913,000-38657 constraints. Model 2 is slightly larger due to additional constraints related to the operation of EBs and charging of ESs, resulting in 21713-24175 continuous variables, 17696-19868 binary variables, and 37170-41304 constraints. Furthermore, both models exhibit stable convergence behavior across all simulations, with solution times ranging approximately from 5 to 18 seconds for Model 1 and 4 to 20 seconds for Model 2 on a 2.50 GHz Intel Core i7-11850H system with 32 GB RAM, running Windows 11 Enterprise 64-bit. These results indicate that the MILP formulations are computationally efficient and suitable for scenario evaluation over time horizons of 672 to 744 hourly intervals.

In this study, both MILP models are developed in a generic and modular manner to ensure they can be easily adapted to different ECs and power systems with similar configurations and objectives. This flexible design allows the models to accommodate diverse operational scenarios, market conditions, and system parameters without extensive reconfiguration. To enhance reproducibility and facilitate further research, all input data used in this study, including electricity spot prices, natural-gas prices, DH demand profiles, and local generation data, are available upon request from the authors.

Simulation results show that replacing GBs with EBs for DH generation represents a robust and flexible solution for sustainable LEMENE. This approach enhances the responsiveness and operational flexibility of smart grids, enabling the utilization of surplus electricity during low spot-price periods or periods of renewable overproduction, thereby improving the overall efficiency of the EC. Simulation results shows that electrification of DH through EBs provides cost savings, emission reductions, and greater energy autonomy, while maximizing the use of local generation and market flexibility. When combined with regulatory incentives that encourage self-consumption, such as lower taxes for EB integration to DH networks and high carbon prices to discourage fossil-fuel systems, EB emerges as an economically resilient alternative to conventional fossil-fueled setups. Despite variations in electricity spot prices, adopting EBs effectively shifts energy import patterns, reduces fossil fuel consumption, and facilitates greater integration of renewable generation, particularly when low-cost or surplus electricity is available.

5.1. Sensitivity analysis

The proposed models are sensitive to several external parameters, including electricity spot and gas prices, and the DH demand profile. To assess the robustness of the results, a systematic sensitivity analysis is conducted on these parameters, as they have a considerable impact on both economic performance and carbon emissions. While the models exhibit moderate sensitivity to secondary parameters such as unit efficiencies and storage units cost related to charging and discharging operations, their influence is comparatively minor, and these parameters are therefore left unchanged to avoid unnecessary complexity without affecting the overall conclusions.

Electricity spot price variation: In Finland, electricity spot prices decreased by approximately 10% in 2025, primarily due to increased renewable generation, while the planned integration of large data center loads may increase prices by 10% in the future (Agency (2025), Eurostat (2024)). Therefore, a variation of ±10% relative to the baseline of the electricity spot prices, shown in Fig. 2, is considered to reflect recent

Table 3
Annual performance metrics - electricity spot price variation.

Variation	Indicator	Model 1	Model 2	Diff.
	Costs (10^3 EUR)	1025.6	884.9	-13.7%
+10%	Emissions (10^3 kg)	2302.7	2299.6	-0.14%
	Local use (MWh)	780.2	1906.8	+144.4%
	Costs (10^3 EUR)	994.1	832.2	-16.3%
-10%	Emissions (10^3 kg)	2295.5	2288.5	-0.31%
	Local use (MWh)	764.5	2111.5	+176%

Table 4
Annual performance metrics - gas price variation.

Variation	Indicator	Model 1	Model 2	Diff.
	Costs (10^3 EUR)	1079.2	895.1	-17.1%
+10%	Emissions (10^3 kg)	2296	2288.8	-0.3%
	Local use (MWh)	778.6.2	2081.6	+167%
	Costs (10^3 EUR)	994.3	820.8	-17.5%
-10%	Emissions (10^3 kg)	2304.2	2136.8	-7.3%
	Local use (MWh)	782.8	1914.7	+144.6%

market trends in Finland. All other parameters are held constant, and simulation results are given in Table 3.

Table 3 shows that a 10% increase in electricity spot prices results in lower annual operating costs for Model 1 compared to the baseline scenario presented in Table 2. When electricity prices are high, Model 1 shifts away from market electricity purchases and relies more on local fossil-fuel-based generation. As a result, its operating costs become lower than those in the baseline scenario, which depends on a mix of locally generated and purchased electricity. In contrast, Model 2 is less sensitive to higher electricity spot prices because a larger share of its electricity demand is satisfied by local generation, thereby limiting its exposure to market price fluctuations. Conversely, a 10% decrease in electricity spot prices reduces operating costs for both models. However, Model 2 achieves greater absolute cost savings due to its higher electricity consumption. Emissions remain largely stable across both price scenarios, indicating that they are driven primarily by fuel type rather than electricity price variations. Nevertheless, when electricity spot prices increase by 10%, Model 1 increases its reliance on fossil-fuel-based heat generation as compared to the baseline scenario, leading to higher emissions. In addition, the higher utilization of local electricity generation in Model 2 is associated with increased CHP operation, leading to higher emissions when compared with the baseline scenario. In addition, Model 2 exhibits a substantially higher level of local electricity utilization, indicating that electrification shifts electricity demand toward local generation, largely independent of market price conditions. These results indicate that Model 2 is less sensitive to fluctuations in electricity spot prices, whereas Model 1's dependence on external electricity increases its exposure to price variability.

Gas price variation: Long-term forecasting of natural gas prices is highly uncertain, as more than 58% of Europe's natural gas supply is sourced from outside the European Union (Zakeri et al. (2023)). Accordingly, a ±10% variation in gas prices is considered in the sensitivity analysis, while all other parameters are held constant, and the results are summarized in Table 4.

When gas prices are varied by ±10% relative to the baseline scenario presented in Table 2, the effects are asymmetric across the two models. In Model 1, a 10% increase in gas prices leads to higher operating costs and a modest decline in emissions, as high gas prices reduce the attractiveness of gas-based heat production during marginal operating periods. By contrast, Model 2 exhibits only minimal changes in both costs and emissions, reflecting its limited reliance on natural gas. Conversely, a 10% reduction in gas prices lowers operating costs in Model 1 but increases emissions due to greater gas utilization, while Model 2 again remains largely unaffected. Overall, these findings demonstrate that gas price variations largely affect the performance of gas-dependent systems, whereas electrified configurations provide greater economic and environmental stability.

Table 5
Annual performance metrics - heat demand variation.

Variation	Indicator	Model 1	Model 2	Diff.
	Costs (10^3 EUR)	1186.1	1003.7	-15.4%
+20%	Emissions (10^3 kg)	2753.1	2746.6	-0.24%
	Local use (MWh)	796.7	2284.8	+187%
	Costs (10^3 EUR)	1433.8	1218.1	-15%
+50%	Emissions (10^3 kg)	3429.6	3427.7	-0.06%
	Local use (MWh)	807.4	2758.4	+242%

Heat demand variation: To account for the potential expansion of LEMENE's DH network to the other areas in the Lempäälä region, an increase in heat demand is expected in the near future. To examine the effects of this increase, additional sensitivity analyses are performed considering a 20% and 50% increase in heat demand relative to the baseline. The results of these simulations are summarized in Table 5.

The sensitivity analysis on heat-demand variation indicates that annual operating costs increase for both models as demand rises. However, Model 2 maintains approximately 15% lower operating costs than Model 1 due to its ability to use locally produced electricity, which becomes increasingly valuable as heat demand increases. Local electricity consumption in Model 2 increases by approximately 3 times compared with Model 1 due to high heat demand and the model's preference for utilizing locally generated electricity for heat generation. Carbon emissions increase for both models with higher heat demand, as expected, but the relative difference between the two configurations remains small, since the variation is related to the heat demand rather than the gas or electricity spot prices. These results demonstrate that electrified DH amplifies its economic benefits while preserving its environmental performance.

5.2. *Limitations*

This study proposes two novel MILP models for comparing fossil-fuel-based DH systems with electrified alternatives. While the analysis provides numerous insights for researchers and EC stakeholders, it is subject to several limitations. The study assumes that LEMENE does not participate in Fingrid's reserve markets for ancillary services and is excluded from the present analysis. Although excluding reserve markets participation, real-time energy price variations, and DH network dynamics simplifies the modeling approach, it also limits the ability to capture additional economic value streams and operational constraints. Including participation in reserve markets for ancillary services could potentially provide extra revenue for EBs, CHPs, and ES units, enhance flexibility utilization, and further reduce emissions. Nevertheless, these effects are secondary to the primary objective of the study, which is to evaluate the techno-economic impact of transitioning from GBs to electrified alternatives under day-ahead market operation. Future work should extend the models to incorporate these elements to provide a more comprehensive assessment of system flexibility, revenue potential, and operational performance.

Both MILP models are deterministic and provide optimal solutions for power dispatch and unit commitment to optimize electricity procurement, local generation, and storage operation under sector-coupled constraints over a monthly horizon. This approach contrasts with common strategies in the literature, such as MPC and stochastic-based optimization, which can adapt to real-time forecast updates and account for uncertainties. However, the MILP models presented in this study offer detailed insights about EC operation, making them particularly well-suited for rigorous comparative techno-economic analysis.

The simulation results demonstrate that Model 2 (EB configuration) provides operational flexibility through electricity procurement shifting and rapid load adjustments. However, a detailed quantification of flexibility metrics, such as ramp rates or explicit grid-service capabilities to address the grid congestion, is beyond the scope of this study. Flexibility is therefore evaluated only in terms of its impact on operational costs, the substitution of gas with electricity, and interactions with electricity spot prices. While the model implicitly captures load shifting and peak-demand reduction through economic optimization, a comprehensive market-oriented flexibility analysis lies outside the scope of this comparative transition study.

This study focuses on minimizing operating costs while maximizing day-ahead electricity sales, represented as a single-objective function in (25). While this objective provides valuable insights, for ECs that promote sustainability, optimizing solely for cost reduction and revenue generation, this can lead to higher fossil fuel consumption and increased environmental impacts. To achieve long-term sustainability, it is essential to incorporate carbon emission minimization as an additional objective, resulting in a multi-objective formulation. A similar multi-objective formulation has been applied in the LEMENE case, considering configurations with GBs only (Ahmed and Vilkko (2025b)). In future, a comprehensive multi-objective or Pareto frontier analysis could be conducted for configurations with both GBs and EBs, providing a more complete assessment of environmental and economic trade-offs.

The current study assumes fixed electricity taxation. Future regulatory changes in electricity taxes or grid tariffs could influence the long-term economic performance of both GB and EB-based configurations. Furthermore, including carbon emission prices in total operating costs would also affect the performance of both models. For instance, higher carbon prices would favor electrified heating, whereas changes in electricity taxation could shift operational cost advantages. Explicitly modeling such policy scenarios is therefore essential to evaluate the resilience of electrification strategies under regulatory uncertainty.

The electricity buying and selling limits imposed by the Elenia grid in the LEMENE system (10 MW for purchases and 4 MW for sales) directly affect both the feasibility and economic performance of the models. These constraints become binding during periods of high demand or high generation, limiting the EB model's ability to purchase electricity at low prices and constraining potential revenue from electricity sales. Consequently, grid capacity restrictions partially reduce the economic benefits of electrification. If LEMENE invests in its own transmission infrastructure in the future, these constraints would become less restrictive, allowing higher revenue generation. In this scenario, reduced dependence on external transmission would alleviate congestion, increase the utilization of locally produced electricity in the EBs, lower operational costs, and enhance overall system self-sufficiency.

The present study focuses on a single established EC; the proposed MILP models are inherently scalable and can be applied to larger or multiple ECs. Computational feasibility primarily depends on the number of time steps and the number of power generation and storage units. Extending these models with additional units is expected to yield solution times that remain manageable when using commercial MILP solvers. For larger ECs or systems composed of multiple interconnected ECs, decomposition techniques, rolling-horizon optimization, or heuristic approaches can be employed to reduce computational complexity. Consequently, the proposed methodology is broadly applicable and can support techno-economic assessments of more complex ECs, while maintaining a practical balance between solution accuracy and tractability.

The simulation results presented in this study not only enhance the operational performance of the DH network in the LEMENE EC but also have direct implications for energy transition and decarbonization policies at both national and European Union levels. By quantifying the techno-economic impacts of replacing fossil-fuel-based boilers with electrified alternatives, the analysis demonstrates that electrified DH systems can achieve significant emission reductions while maintaining economic viability. These findings align with key policy objectives, including the European Green Deal target of net-zero emissions by 2050 and Finland's national strategy to increase the integration of local renewable energy resources in DH networks (European Commission (2019), Jensen (2024)). Therefore, the simulation results provide valuable insights for policymakers and EC stakeholders to support investment decisions in electrified infrastructure, grid reinforcement planning, and the design of incentives to promote the adoption of low-carbon DH technologies.

6. Conclusion

This study introduces novel MILP-based models for the LEMENE EC in Finland, integrating both renewable and conventional generation with energy storage to provide electricity and heat in a coordinated manner. These models combine unit commitment and economic dispatch to compare two system configurations: the current setup with GBs (Model 1) and a proposed configuration in which GBs are replaced by EBs (Model 2). By simulating one full year of operational data, this study enables a detailed assessment of operational costs, day-ahead electricity revenues, carbon emissions, and local energy utilization under realistic market and demand conditions. The results demonstrate that Model 2 achieves substantial long-term benefits, including an approximate 10% reduction in annual carbon emissions, with peak winter reductions exceeding 60%. In addition, Model 2 enhances economic performance by reducing operating costs and significantly increasing the use of locally generated electricity by more than 160%, thereby strengthening energy self-sufficiency. Although current transmission fees constrain immediate economic gains, the potential removal of these fees would further improve the cost-effectiveness of electrified DH. Furthermore, this study highlights the strategic value of EBs in advancing Europe climate objectives and the electrification of DH networks. The proposed models are also scalable and adaptable to larger or more complex ECs, providing a flexible tool for techno-economic assessment. Overall, this work offers supports the transition toward low-carbon, electrified EC, providing actionable insights for policymakers.

For future work, the models will be extended to include LEMENE's participation in reserve markets for ancillary services, enabling a more comprehensive evaluation of economic opportunities, operational flexibility, and integration of additional renewable and storage assets. Furthermore, to achieve long-term sustainability, it is essential to incorporate carbon emission minimization as an additional objective, resulting in a multi-objective model formulation to provide a more complete assessment of environmental and economic trade-offs.

CRediT authorship contribution statement

Hussain Ahmed: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization; **Matti Vilkko:** Validation, Supervision, Project administration, Funding acquisition.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:
Matti Vilkko reports financial support was provided by Business Finland. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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