UDK 621
https://doi.org/10.36296/1819-8058.2025.4(83).8-17

COST-OPTIMISATION MODELLING OF LOCAL LEVEL CROSS-VECTOR FLEXIBILITY IN COUPLED DISTRICT HEATING AND ELECTRICITY NETWORKS: A CASE STUDY OF KUNGSBACKA, SWEDEN

Received Nov. 27, 2025; accepted Dec. 09, 2025
Available online Dec. 31, 2025

Lysenko O.[1], Mata É.[2], Sobha P.[3]

Author for correspondence: Lysenko Olga,
e-mail: olga.lysenko@ivl.se

[1] PhD
https://orcid.org/0000-0001-7085-7796

[2] PhD
https://orcid.org/0000-0002-0735-3744

[2] Energy system modeler
https://orcid.org/0000-0003-1022-6014

[1, 3] IVL Svenska Miljöinstitutet AB, Stockholm, Sweden

[2] IVL Svenska Miljöinstitutet AB, Gothenburg, Sweden

Abstract. *This study presents a local-level cost-optimization analysis of cross-vector flexibility between district heating (DH) and electricity systems in the municipality of Kungsbacka, Sweden. Using a TIMES model, we assess the techno-economic performance of integrated flexibility solutions, including electric boilers, heat pumps, rooftop photovoltaic (PV) panels, storage in electric battery and thermal storage, solar thermal collectors, and smart appliances, under varying electricity and biomass price scenarios. Results show that while the base and implemented configurations remain dominated by biomass-fired generation, the inclusion of electricity-based heating technologies, particularly the electric boiler, enables cost-efficient and low-emission operation during periods of high biomass prices. The analysis also reveals notable differences in system running costs across scenarios, with substantial long-term cost reductions observed only when investment flexibility allows broader adoption of power-to-heat options. The scenarios reveal a long-term transition toward electrified DH, where heat pumps and thermal storage become central to system optimization. Thermal energy storage contributes significantly to peak shaving and load shifting, enabling the system to respond to hourly electricity price variations. Consumer-side resources, including rooftop PV, batteries, and dual-input smart appliances, further enhance local flexibility by increasing self-consumption and shifting energy carriers between electricity and DH. The findings confirm that combining multiple cross-vector flexibility measures can reduce operating costs, enhance renewable integration, and strengthen local energy resilience, supporting a transition toward climate-neutral district energy systems. These results underscore the importance of price-responsive operation and coordinated deployment of flexibility technologies in local-scale decarbonisation pathways.*

Keywords: *Cross-vector flexibility, district heating, power-to-heat, TIMES model, energy system optimization, renewable integration, local energy systems; decarbonization.*

МОДЕЛЮВАННЯ ВАРТІСНОЇ ОПТИМІЗАЦІЇ ЛОКАЛЬНОГО РІВНЯ МІЖСИСТЕМНОЇ ГНУЧКОСТІ У ПОЄДНАНИХ МЕРЕЖАХ ЦЕНТРАЛІЗОВАНОГО ТЕПЛОПОСТАЧАННЯ ТА ЕЛЕКТРОПОСТАЧАННЯ: КЕЙС СТАДІ МІСТА КУНГСБАКА, ШВЕЦІЯ

Отримано 27 лист. 2025 р.; рекомендовано до публікації 09 груд. 2025 р.
Доступно онлайн 31 груд. 2025 р.

Лисенко О.[1], Мата Е.[2], Собха П.[3]

Автор для кореспонденції: Лисенко Ольга,
e-mail: e-mail: olga.lysenko@ivl.se

[1] PhD
https://orcid.org/0000-0001-7085-7796

[2] PhD
https://orcid.org/0000-0002-0735-3744

[2] Фахівець з моделювання енергетичних систем
https://orcid.org/0000-0003-1022-6014

[1,3] IVL Шведський інститут досліджень довкілля, Стокгольм, Швеція

[2] IVL Шведський інститут досліджень довкілля, Гетеборг, Швеція

Анотація. *У цьому дослідженні представлено аналіз вартісної оптимізації на локальному рівні щодо міжсистемної гнучкості між системами централізованого теплопостачання (ЦТ) та електропостачання в муніципалітеті Кунгсбака (Швеція). За допомогою моделі TIMES оцінено техніко-економічну ефективність інтегрованих рішень гнучкості, включно з електричними котлами, тепловими насосами, даховими фотоелектричними системами, акумуляторами електроенергії, сонячними тепловими колекторами та «розумними» побутовими приладами, в умовах різних сценаріїв цін на елек-*

троенергію та біомасу. Результати показують, що хоча базові та впроваджені конфігурації залишаються переважно зосередженими на виробництві енергії на біомасі, залучення технологій опалення на основі електроенергії, зокрема електричного котла забезпечує економічно ефективну та низьковуглецеву роботу системи в періоди високих цін на біомасу. Аналіз також виявляє помітні відмінності в експлуатаційних витратах системи в різних сценаріях, причому істотне довгострокове зниження витрат спостерігається лише в тих випадках, коли гнучкість інвестицій дозволяє ширше застосовувати варіанти перетворення електроенергії на тепло. Сценарії демонструють довгостроковий перехід до електрифікованої системи ЦТ, де теплові насоси та теплові акумулятори стають ключовими елементами оптимізації. Зберігання теплової енергії значно сприяє згладжуванню пікових навантажень і перерозподілу навантажень, дозволяючи системі реагувати на погодинні коливання цін на електроенергію. Ресурси на стороні споживачів, включно з даховими фотоелектричними системами, акумуляторами та смартприладами з подвійним входом, ще більше підвищують місцеву гнучкість за рахунок збільшення власного споживання та перерозподілу енергоносіїв між електроенергією та централізованим теплопостачанням. Отримані результати підтверджують, що поєднання декількох заходів міжсистемної гнучкості може знизити експлуатаційні витрати, підвищити рівень інтеграції відновлюваних джерел енергії та зміцнити локальну енергетичну стійкість, підтримуючи перехід до кліматично нейтральних систем централізованого теплопостачання. Ці результати підкреслюють важливість оперативного реагування на цінові зміни та скоординованого впровадження гнучких технологій у процесах декарбонізації на місцевому рівні.

Ключові слова: *міжсистемна гнучкість; централізоване теплопостачання; power-to-heat; модель TIMES; оптимізація енергосистем; інтеграція відновлюваних джерел; локальні енергосистеми; декарбонізація.*

Introduction. In Sweden, Distribution System Operators (DSOs) play a crucial role in managing local electricity distribution networks. They manage the medium and low-voltage distribution networks that deliver electricity from the transmission network to end-users and are responsible for ensuring a reliable supply of electricity, maintaining and developing the grid infrastructure, and integrating renewable energy sources. The regulation also encourages DSOs to adopt innovative solutions and technologies that enhance grid performance and flexibility.

The cooperation between DSOs and consumers is essential to keep the supply and demand balanced and enhance grid flexibility. Consumers may contribute through demand response (DR) programs (by reducing electricity use during peak periods and/or shifting high-load appliances to off-peak hours, reducing the strain on the distribution network and the risk of outages or the need for costly short-term purchases [1]; through energy efficiency measures (which decrease overall electricity demand and limit the need for infrastructure upgrades and maintenance costs); through distributed renewable generation and energy storage (with smart meters and real-time data exchange enabling DSOs to operate local grids more effectively); or through participation in energy communities (with collectively management of energy production and consumption). Together, these mechanisms consider flexibility across the broader energy system rather than focusing solely on electricity supply and demand.

At the local and urban scales, technologies like electric boilers, heat pumps, and thermal storage integrated with rooftop PV and battery systems provide enhanced operational efficiency, better renewable resource usage, and reduced carbon emissions [2], [3]. Heating systems, in particular, offer multiple flexibility services to the electric power system by either consuming excess electricity, e.g., during the times of high renewable generation and consequently low electricity prices, or by generating electricity (together with heat – cogeneration plants) during the periods of low renewable output and high electricity prices. Both individual technologies (e.g., electric boilers or heat pumps installed in individual buildings) and centralized heating technologies as district heating (DH) have significant potentials of providing such flexibility services and therefore contribute to higher shares of renewable energy sources (RES) in the energy system [4], [5], [6].

DH systems flexibility services are commonly categorised into flexibility of heat sources, heat generation units, networks and thermal energy storage (TES), markets, and consumers [7] [8] [9]. Flexibility at the heat-source level arises from the ability to utilise a range of fuels and renewable sources, such as biomass, waste heat, solar thermal energy, or electricity-driven heating. Generation units—including boilers, combined heat and power (CHP) plants, heat pumps, and electric boilers—provide thermal or electrical flexibility depending on their configuration. DH networks and TES enable peak shaving and temporal shifting of heat production, while buildings contribute through thermal inertia, smart thermostats, decentralised production, and controllable appliances [10]. Together, these mechanisms illustrate the inherent potential of DH systems to interact dynamically with electricity grids and support increased integration of renewable energy.

A substantial body of research has advanced the understanding of energy system flexibility, providing valuable insights into long-term transitions and multi-sector interactions. Studies at regional or national scales capture broad trends but necessarily simplify the unique behaviours and constraints that characterize local energy systems, such as spatially diverse demand patterns, infrastructure limitations, and the role of local actors, thereby underrepresenting the complexity inherent in local-scale energy transitions [11]. Progress has been make in modelling individual flexibility technologies, like batteries, PV systems, or heat pumps, while integrated cost-optimisation frameworks that combine multiple flexibility options remain scarce [11], [12]. Modelling of dual-input smart appliances capable of using either electricity or DH hot water, and hybrid system models that combine electric boilers, heat pumps, and thermal storage have shown cost effectiveness, yet remain rare in mainstream frameworks [13], [14]. A few studies have assessed how fluctuations in electricity or biomass pricing influence investment decisions and operational strategies for flexibility resources in local systems [15]. Notably, sector-coupled models are highly sensitive to price changes, as shown by sensitivity analyses of production mixes [16], [17] and stochastic operational planning approaches [18]. Furthermore, power-to-heat configurations with thermal storage emerge as risk-mitigating solutions under price volatility [15], [19]. In parallel, several articles [20], [21] emphasize the critical need for aligning models with real-world demonstration data to validate assumptions and ensure practical relevance for operational and decision-making support. Yet there remains a need for local-scale, integrated modelling approaches that combine multiple flexibility measures, account for price volatility, and are validated against empirical implementation data.

Objective of the work. This study aims to investigate the potential of cross-vector flexibility between DH and electricity systems at the local level, with explicit assessment of how different flexibility technologies interact under varying energy price conditions and with a focus on how combined flexibility measures can enhance renewable energy utilisation, reduce operational costs, and improve system resilience under varying energy price conditions. Using the case of Kungsbacka, Sweden, the study seeks to generate evidence on the techno-economic value of integrating multiple flexibility options, and provide insights into their optimal deployment strategies by comparing currently implemented solutions with future cost-optimal configurations.

Materials and methods.

Energy flexibility. We consider five categories of flexibility sources [7], [8], [9]:

Heat sources: DH systems can utilize a range of fuels and renewable heat sources, such as biomass, waste heat, solar thermal, and electricity-driven heating. Systems with multiple or switchable energy inputs are inherently flexible, as operators can adjust production based on fuel availability and market conditions. DH systems using electricity-based heat technologies (e.g., heat pumps or electric boilers) also provide direct power flexibility by shifting or modulating their electricity consumption.

Heat generation units: The flexibility of DH systems largely depends on their generation technologies. Combined heat and power (CHP) plants can produce both heat and electricity, offering direct power flexibility and supporting grid balancing. Heat-only units, such as boilers, offer thermal flexibility within the DH system, while power-to-heat (P2H) technologies like heat pumps and electric boilers directly connect the DH and electricity sectors, enabling cross-vector flexibility.

DH network and thermal energy storage (TES): TES systems balance supply and demand over time, allowing peak shaving and load shifting. They can be centralized or distributed and vary from simple hot-water tanks to large underground storages. The DH network itself also provides short-term storage capacity by modulating supply temperatures. While TES does not directly interact with the electricity grid, it enhances the operational flexibility of CHP and P2H units.

Heat consumers: Buildings connected to DH networks can contribute to flexibility through demand response, thermal storage, and decentralized generation. Smart thermostats, control systems, and insulated water tanks allow heat demand shifting in response to price or grid signals. Buildings with on-site renewables or cogeneration units can also export surplus energy, further supporting system balancing.

Description of the Kungsbacka demo site. Demo case is located in Kungsbacka Municipality (Halland County, Sweden) in the parish of Fjärås. Fjärås has a population of approximately 2700 and area of 269 hectares. It has a local DH network, which comprises:

- Two biomass-fired (pellets) boilers of 3.5 MW and 1.5 MW of installed capacity
- Two fossil fuel oil-fired boilers of 4.0 MW and 1.5 MW of installed capacity
- Solar collectors of 45 kW of installed capacity.

Annual heat generation in 2022 totalled 11,806 MWh from biomass boilers, 25.5 MWh from the DH-connected solar collectors, and 0.7 MWh from fossil oil. While the share of heat generated from fossil oil in 2022 was insignificant, previous years showed higher levels, i.e. 67 MWh in 2020 and 42 MWh in 2021. Heat generation from fossil oil increases the production cost and conflicts with the environmental goals of the DH company of fully eliminating fossil-based heat.

The total heat delivered to customers in 2022 was 8970 MWh, corresponding to heat losses in the DH network of 24%. The heat is distributes to substations, at a relatively constant supply temperature of around 90 °C. In each substation, the delivered heat is is transferred to the building through heat exchangers that produce domestic hot water and heating water for distribution to rooms and tapping points. The connection between the substation and the building heating system is regulated by a digital unit controller (DUC) based on the outdoor temperature curve. The indoor spaces are heated via radiators or underfloor heating. In the passive buildings which constitute the demo-site (residential apartments, a pre-school and a group-home), space heating follows a slightly different configuration: the pre-school relies largely on a heat exchanger installed in the ventilation system, while the group-home uses both the heat exchanger, and radiators and/or floor heating. Each indoor space, for example, an apartment, includes a sensor that fine-tunes room temperature to approximately 21 °C; temperatures can be lowered but not raised. Domestic hot water is also controlled via a DUC to maintain a minimum temperature of 55 °C. Overall heat control is managed through indoor temperature and humidity sensors, supported by a Building Energy Management System (BEMS) developed for the site.

In the substation at the demo site, there are individual heat and electricity generation and storage units. 605 kW of solar collectors are installed on buildings roofs of the demo-site area, providing 473 MWh of heat in 2022. These collectors are not coupled to the DH system; instead, generated heat is stored in on-site thermal storages (combined volume: 134 thousand litres, ~7.8 MWh heat capacity) and used to cover the heating and hot water demand of the buildings on which the collectors are installed. Buildings with these solar collectors and storage units are also DH-connected, enabling flexible switching between local solar heat or DH based on the cost of heat generation in the DH system, solar irradiation, and the energy content of the storage units.

The demo-site area also contains distributed electricity resources relevant for flexibility. Rooftop solar PV installations total 86 kW and there is an electric battery (17.4 kWh of electric capacity). These assets allow buildings to choose between the self-generated PV-electricity and electricity purchased from the grid, providing a degree of power flexibility that can support the local DSO.

Together, the existing DH infrastructure, decentralised solar thermal systems, rooftop PV, and battery storage define the technological baseline of the Kungsbacka demo site. We incorporate these components into the TIMES model to evaluate their current performance and potential contributions to cross-vector flexibility.

Model Description. The effects of activated flexibility measures on the heat and electricity supply at the district level, and consequently on the local electricity grid, are analysed using TIMES (The Integrated MARKAL-EFOM System) model generator [22], [23].

TIMES is a technology-rich, bottom-up model generator, which uses linear programming to produce a least-cost energy system design, optimized according to several user constraints over a predefined time horizon, usually a few decades. The studied energy system is represented by different processes that are connected by flows of commodities. Each process (such as, e.g., an energy conversion technology – heat pump) is described by its input and output commodities, efficiency, availability, lifetime, costs, and possibly other parameters. Each commodity (such as e.g., a fuel – biomass) is described by its availability, extraction or import cost and environmental impacts. The model minimizes the total system cost, i.e., the sum of the running and investment costs, of the modelled energy system while assuring that the energy system meets the energy service demands over a time horizon. The model assumes perfect foresight in that all investment decisions are made in each investment period with full knowledge of future events.

In this study we developed a TIMES model of the heating and electricity system of the demo-site area (only buildings connected to the DH system). The model minimizes the cost of meeting the total heating and electricity demand of the demo-site area (Fig. 1). The heating and electricity demand of the demo-site area is given to the model exogenously and can have different disaggregation levels (levels of detail), which depend on the available statistical data. The heat supply side includes both centralized (DH) and decentralized (individual) heating technologies. The electricity supply side includes the possibility of importing (using) electricity from the electric grid as well as generating electricity locally by distributed electricity generation technologies, such as solar panels and small-scale wind turbines (technologies that do not need to sell the generated electricity to the wholesale market, as the national regulation demands). The DH and local electrical grids are represented in the model in a simplified way, in terms of energy flows and losses. Key heating technologies are:

- Heat pumps (ambient and waste heat)
- Electric boiler
- Energy storage in buildings
- Grid-connected DH storage
- Solar thermal

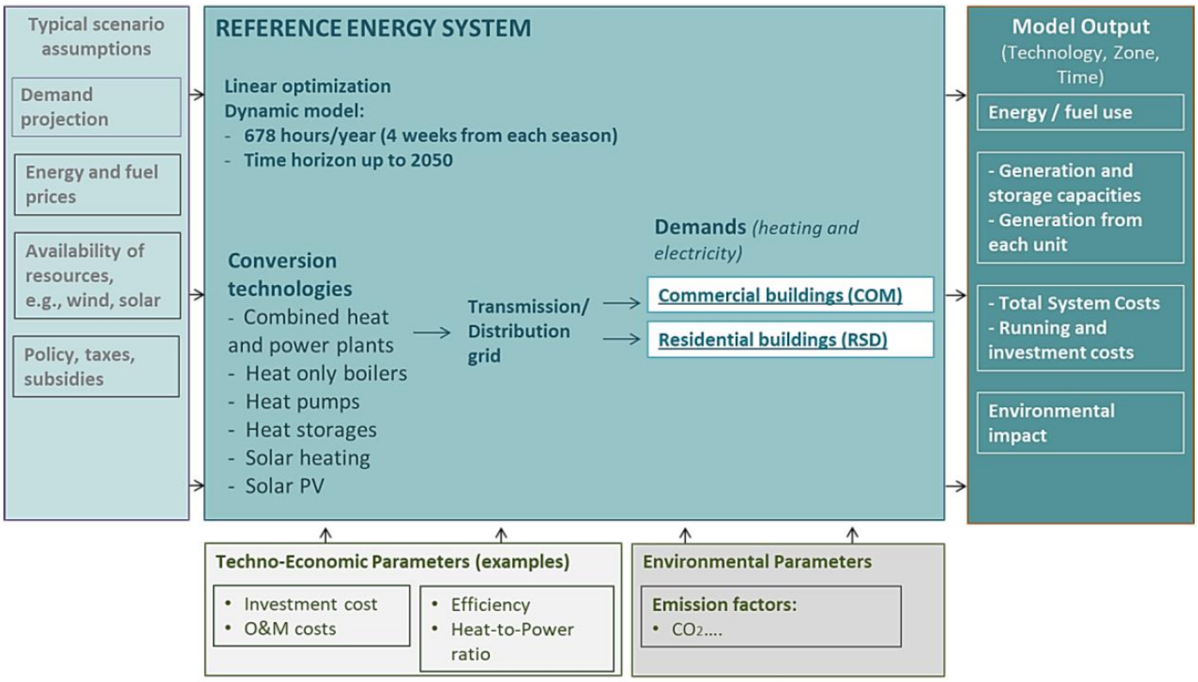

Fig. 1. Schematics of the model

Scenarios of cross-vectorial flexibility. Scenario analysis is performed using the developed energy system model to study the effects of flexibility options on the development and operation of the district energy system of the Kungsbacka demo-site. Three scenarios were defined to represent the three groups of flexibility options considered in this project (Table).

A business as usual (BAU) *scenario* is designed to represent a future up until 2050, in which the studied district energy system is operated in a way closest to the operation as of 2022. The heat and electricity will be supplied to the demo-site area by the same technologies as of 2022, i.e., the DH system will remain the main heat supplier and rely on the biomass-fired boilers supported by fossil oil-fired units for peak generation. Electricity will be supplied form the local grid or by the existing solar panels. The heat and electricity demand and their respective profiles will also be unchanged. Investments in new heat and electricity generation and storage technologies will not be allowed in the model with one exception - the existing boilers will be replaced in the future by new ones of the same type and capacity (biomass boilers phased out by 2040 and oil boilers – by 2030).

Table. Defined scenarios and cases modelled

Scenario name	Case No.	Electricity price		Biomass price	
		Reference	High	Reference	High
BAU scenario	BAU	YES	NO	YES	NO
Implemented scenario	I1	YES	NO	YES	NO
	I2	NO	YES	YES	NO
	I3	YES	NO	NO	YES
	I4	NO	YES	NO	YES
Planned scenario	P1	YES	NO	YES	NO
	P2	NO	YES	YES	NO
	P3	YES	NO	NO	YES
	P4	NO	YES	NO	YES

An implemented scenario is designed to study the effects of the flexibility options implemented during the project's timeline on the district energy system of the Kungsbacka demo-site area. It includes the same input data assumptions and identical constraints as in the reference scenario. It also includes, i) electric boiler at the demo-site buildings, connected to the thermal storage, ii) smart washing machines and dish washers, and iii) "passive customers" utilization of the thermal inertia of buildings as thermal energy storage. Other investments (except for reinvestments in heat generation boilers) are still forbidden in the model.

A potential scenario is defined to explore other, cost-attractive flexibility options to be added (invested in) in the Kungsbacka demo-site area. Here, all the input assumptions are the same as in the previous two scenarios, but with one difference – the model is not forced to reinvest in the same biomass- and oil-fired capacities in the future but is allowed to choose freely the cost-optimal type and size of new heat and electricity generation/storage technologies out of the possible investment options. This scenario's objective is to show the unconstrained (in terms of investments) energy system development pathway. A narrower focus is on understanding if a stronger link (additional investments) between the heating and electricity systems could be found by the model in addition to the solutions implemented during the project's lifetime.

The proposed scenarios represent alternative pathways for the development of the local energy system, all evaluated under the same set of input parameters, such as fuel prices, fuel availability, and electricity prices. To explore a wider range of possible system evolutions, these scenarios were further tested by varying selected parameters in the model.

Results and discussion.

Running costs. Fig. 2 illustrates the annual running costs of the energy system under different scenarios (BAU, Implemented I1–I4, and Potential P1–P4) for the years 2023, 2030, 2040, and 2050. The BAU scenario maintains stable but relatively high running costs, driven mainly by fuel expenditures and taxes.

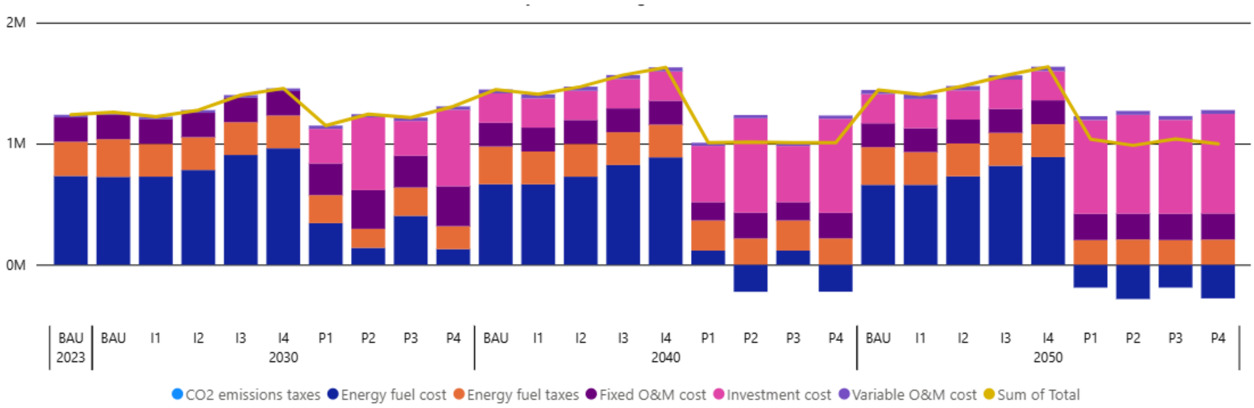

Fig. 2. Comparison of annual system running costs across scenarios (BAU, Business as usual; I, Implemented flexibility; P, Potential flexibility), EURO

The implemented flexibility scenarios (I1–I4) introduce modest cost variation. Although the cost reductions are limited, these scenarios demonstrate how already-implemented measures alter operational behaviour, especially under high or volatile energy prices. Notably, I4, reflecting high biomass and electricity prices, results in the highest running costs, particularly in 2040 and 2050. In contrast, the Potential scenarios (P1–P4) show a clear downward shift in total running costs, especially under P3 and P2, driven by accelerated fuel switching, increased use of electricity-based technologies, and more efficient utilisation of renewable and ambient heat. Fuel-related costs (blue and orange) shrink significantly in the potential scenarios, due to the adoption of low-cost and low-emission technologies (e.g., solar, heat pumps), illustrating the system-wide economic benefits of deeper cross-vector integration. Operation and maintenance (O&M) costs grow more prominently in optimized systems but remain offset by lower fuel and emissions costs, resulting in an overall cost reduction.

Together, these results show that cost savings depend strongly on the availability of investment flexibility and the ability of the system to respond to price signals through power-to-heat technologies and thermal storage. While BAU maintains a stable but costly path, more dynamic and diversified system configurations (as seen in Potential scenarios) offer economic advantages and resilience against future price volatility.

Fuel use in the DH system. Fig. 3 presents the annual fuel consumption of the DH system across all modelled scenarios—BAU, Implemented (I1), and Potential (P1) for the years 2023, 2030, 2040, and 2050. Wood pellets remain the dominant fuel in BAU and implemented scenarios across all years, reflecting the continuity of biomass-based generation.

In Potential scenarios (P1), the system transitions toward diverse low-carbon energy sources, particularly:

- Electricity from the grid, used in electric boilers and heat pumps,
- Outdoor air and waste heat, representing renewable and recovered heat for heat pump operation.

This transition accelerates after 2030, demonstrating how investment flexibility enables a structural shift from combustion-based to electrified and renewable heat supply. Starting from 2030 and expanding through 2050, these cleaner energy sources significantly displace wood pellets, reflecting a shift to electrified DH. This shows a clear trajectory of decarbonization and diversification in the DH system.

The BAU and Implemented scenarios remain reliant on biomass and fossil-based fuels, with limited use of electrification or renewable heat sources. This indicates that operational flexibility alone is insufficient to drive deep decarbonisation without accompanying investment flexibility. In contrast, Potential scenarios unlock substantial fuel switching, reducing dependency on combustion fuels and integrating clean electricity and ambient heat. The less prominent but relevant contributors, such as solar thermal and bio-oils, enhance flexibility and support system resilience.

These results confirm that system-wide transformation is contingent on investment flexibility, enabling the DH sector to adopt a broader mix of sustainable fuels. In both winter and summer BAU scenarios, the DH system remains predominantly biomass-based, with minimal solar or storage contributions. Solar thermal output is visible only during daytime in summer, offsetting a small share of boiler operation but not significantly altering system behaviour. The limited power-to-heat technologies or active storage imply the limited influence of electricity price variations on DH operations. Although their absolute contribution is modest, they complement heat pumps and storage, strengthening the system's ability to respond to price and demand variations.

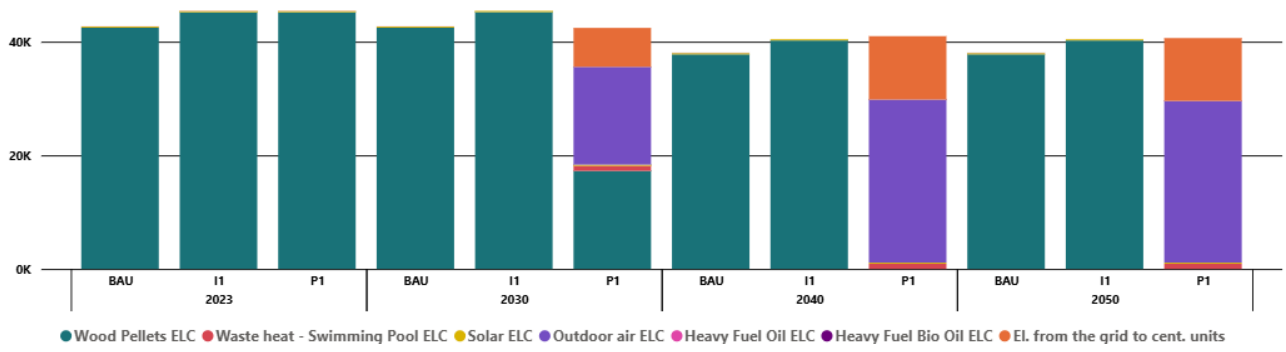

Fig. 3. Fuel use by DH facility by scenario and year, GJ

Implemented scenarios: electric boiler operation. The contribution from the electric boiler remains relatively low, with the wood pellet boiler continuing to dominate the heat supply to the DH network. However, the highest levels of heat generation from the electric boiler are observed in the Implemented Scenarios (I3 and I4) (Fig. 4). The cross-vectorial approach, which facilitates the installation and integration of the electric boiler, clearly demonstrates the technical and operational potential of this technology within the district heating system. This result highlights the electric boiler's ability to respond to electricity and biomass price signals and confirms its role as a strategic complement to biomass-fired boilers. This impact becomes particularly evident under conditions of high biomass prices, where the electric boiler, serves as a flexible and low-emission alternative to traditional biomass-based systems.

Although the current share remains limited, the results underscore the value of cross-vectorial flexibility in enabling future expansion, optimization, and decarbonization of heat supply within the DH network. In particular, they show how the introduction of even a single power-to-heat technology can support sector coupling and reduce system exposure to fuel price volatility.

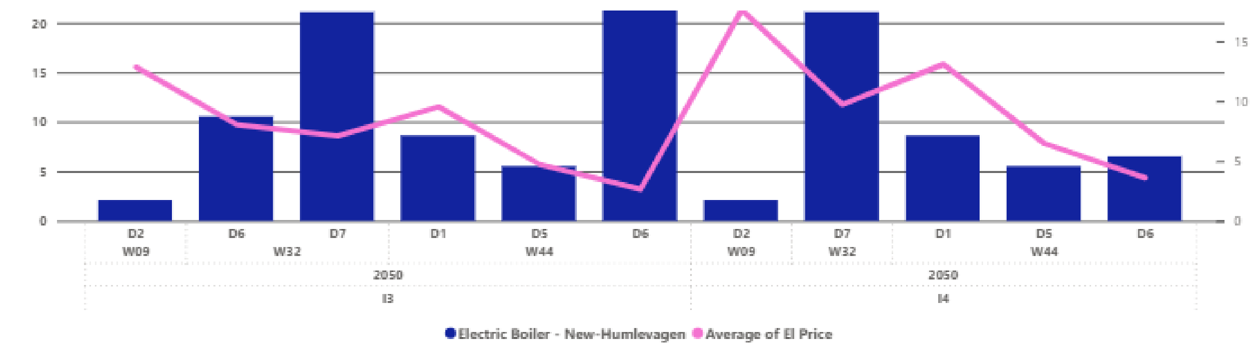

Fig. 4. Electric boiler heat supply (left axis, GJ) and electricity price (right axis, €/MWh) comparison for Implemented Scenarios (I3 and I4), year 2050

Potential scenarios: heat pumps and thermal storage. Fig. 5 shows the daily heat supply to the DH network and the corresponding electricity market price during selected weeks in 2050, under Scenario P1 (with full investment freedom and low electricity price). They illustrate how various flexibility technologies interact with market conditions to optimize system operation.

For example, in week 9, 2050 (Winter Week), the DH system is predominantly supplied by heat pumps, which operate steadily across the week. A notable discharge event is observed during day D2, when energy storage in buildings is released, covering a significant portion of peak demand. The electric boiler is not used this week, indicating that low electricity prices are still not more favourable than heat pump operation at that time. The integration of building-level storage helps shave peak demand and reduce load on the heat pumps during brief high-demand periods.

In week 44, 2050 (Autumn Week), during a lower-demand period, heat pumps still operate as the main source, though with more variability. As electricity prices drop, the system takes advantage of grid- and building-level storage (days 2 and 3), filling and discharging based on cost optimization. The bars show coordinated use of DH grid storage and building thermal storage, with discharges aligned to periods of high electricity price, reflecting intelligent dispatch and load shifting. Waste heat and solar thermal contribute marginally during daytime hours.

As shown under Scenario P1, where full flexibility and investment freedom are permitted, heat pumps become the dominant technology, thermal energy storage (both in buildings and the DH grid) plays a crucial role in flattening peaks, shifting load, and reducing costs. The system responds smoothly to electricity price signals, demonstrating that cross-sectorial flexibility enhances economic and operational efficiency in a low-carbon DH system.

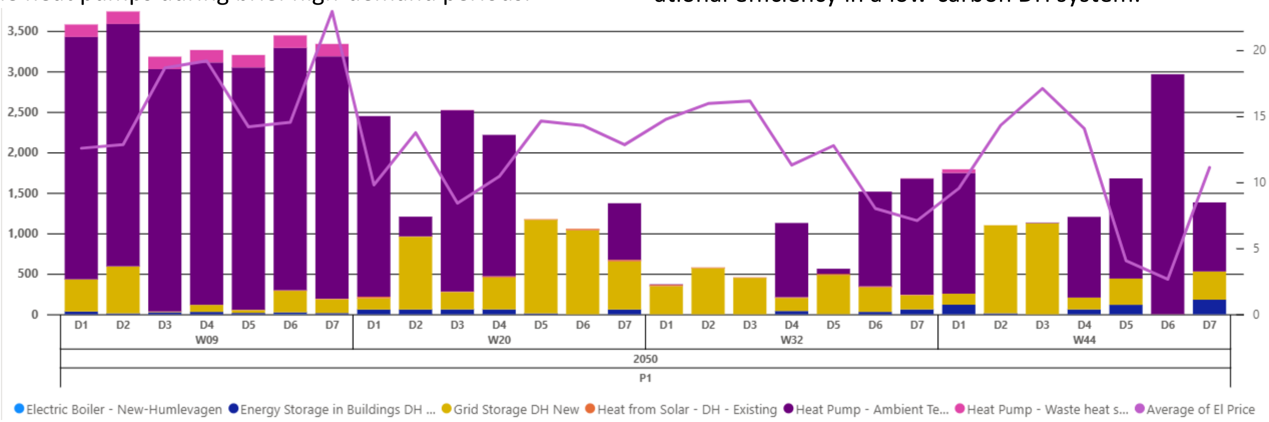

Fig. 5. Heat supply to DH (left axis, GJ) and electricity price (right axis, Euro/MW) for scenario P1, year 2050

Local electricity management. Fig. 6 illustrates the operation of the different local electricity systems across the scenarios I1 (2050), and P1 (2050), based on hourly data from Week 9. BAU scenario results are very similar to those of Scenario I1. They show how electricity supply composition, rooftop PV generation, and battery storage operation respond to electricity price signals and available flexibility options.

In the I1 scenario, grid electricity remains dominant, but battery use becomes more active and targeted. This indicates that implemented flexibility measures already enhance local responsiveness to price variations, even without new investments. Discharge is visible in mid-morning (W09D7H10).

However, there is still no discharge during the highest price periods, suggesting improved but still limited flexibility. Solar PV input is also minimal in I1, as no new rooftop PV is added. P1 represents a fully optimized system with expanded rooftop PV (pink) and coordinated storage integration. Under these conditions, the demo-case exhibits clear self-consumption optimisation and reduced dependence on the grid.

During midday hours (W09D7H12–H16), rooftop PV meets most of the demand. In the evening, grid storage (orange) supply electricity during price peaks, effectively reducing reliance on the grid when prices are highest. This behaviour demonstrates a high degree of price-responsive flexibility and highlights how investments in distributed PV and storage enhance resilience and reduce operational costs.

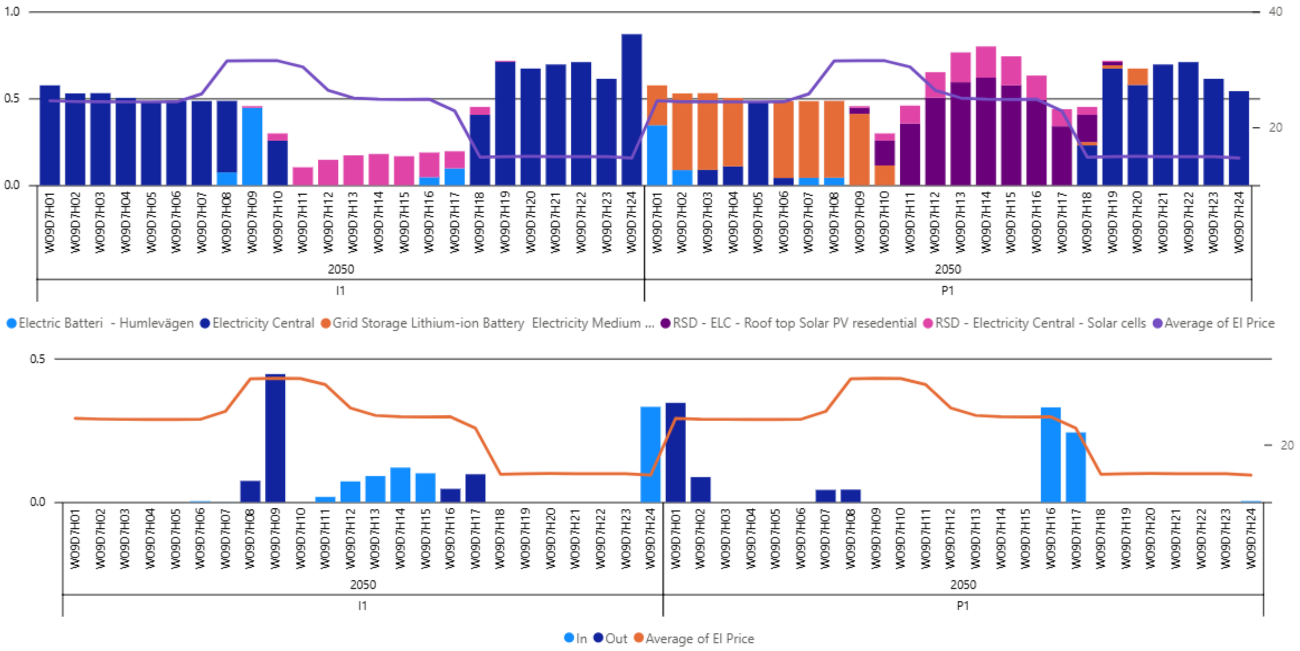

Fig. 6. Operation of local electricity systems: PV, battery storage, and grid interaction (left axis, GJ) and electricity price (right axis, Euro/MW) for winter week, 2050, scenarios I1 and P1

Smart appliance flexibility. Fig. 7 compares hourly smart appliance energy use across four scenarios: BAU, Implemented I1, Implemented I4, and Potential P1, for a representative weekday in 2050. These appliances, such as dishwashers and washing machines, are capable of using either electricity or DH hot water. The total appliance load is shown in gigajoules (GJ), with energy carrier breakdown: electricity and DH.

In the BAU scenario, all appliance energy demand is met with electricity, following a conventional use pattern that gradually increases during the day and peaks in the evening. In Scenario I1, most appliance operation shifts to DH hot water, reducing electricity demand.

A small share of electricity use remains visible during midday hours. Scenario I4, which assumes higher energy prices, reflects further substitution of electricity with DH energy. Nearly all appliance demand is met with DH, with only a minimal share of electricity used. The daily use pattern remains similar, indicating that while energy carrier choice has shifted, the appliance schedule has not.

In the P1 scenario, a more balanced and dynamic configuration appears. Both DH and electricity are used across the day, with electricity dominating from late morning through early evening. This reflects a system where smart appliances are configured to select between DH and electricity based on predefined rules or cost-effectiveness, though again without altering the time of use.

These results show that smart appliances primarily contribute through energy-carrier switching rather than temporal load shifting. Even so, this switching provides meaningful demand-side flexibility, helping to reduce peak electricity use and supporting integration of low-cost or renewable heat sources when available.

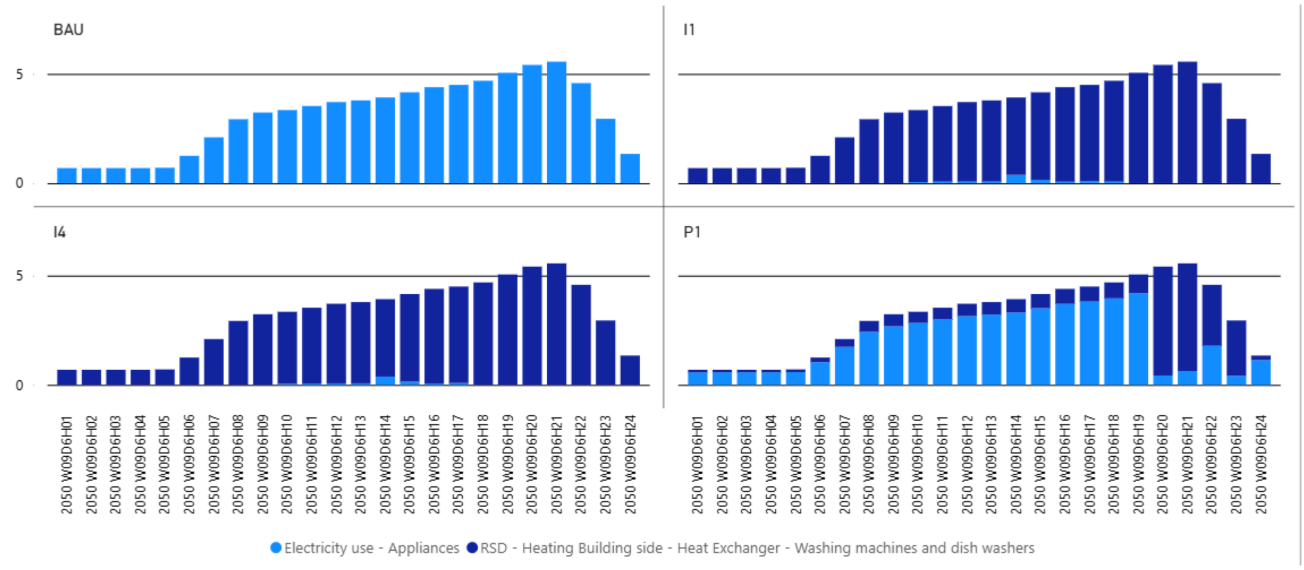

Fig. 7. Smart appliances operation 2040 (winter day), GJ

Conclusion. This study investigated the techno-economic potential of cross-vector flexibility in a local energy system coupling district heating (DH) and electricity networks, using the Kungsbacka demo site in Sweden as a case study. The TIMES cost-optimisation model enabled an integrated assessment of electricity, heating, and storage technologies under varying energy price scenarios. The results show that while biomass remains the dominant heat source in the reference (BAU) and implemented scenarios, introducing flexibility technologies such as electric boilers, heat pumps, and smart appliances leads to gradual diversification of the energy mix and improved operational adaptability. In particular, the installation of the electric boiler further enables sector coupling. Although its contribution to total heat supply remains moderate, the technology shows clear operational and environmental advantages under high biomass price conditions, offering a low-emission and cost-competitive complement to traditional bio-based generation.

A key finding is the substantial reduction in long-term operating costs observed in the potential scenarios, driven by fuel switching away from biomass, increased use of electricity-based heating, and reduced emissions-related costs. The scenarios also reveal a pronounced transition from biomass to electrified heat supply, with heat pumps becoming the dominant technology by 2050 and ambient and waste heat replacing combustion fuels. Thermal energy storage—both at the building level and within the DH network—plays a central role in enabling load shifting, peak shaving, and cost-efficient utilisation of low-price electricity, illustrating its importance in fully flexible systems.

The analysis further highlights the strong price-responsiveness of flexible technologies: electric boilers operate primarily under high biomass prices, heat pumps adapt to electricity price variations, and storage systems charge and discharge according to hourly market conditions. Consumer-side resources also contribute meaningfully to system performance; rooftop PV and batteries increase local self-consumption and reduce grid imports during high-price hours, while smart appliances provide additional sector-coupling flexibility by shifting energy carriers between electricity and DH. Notably, smart appliances shift the energy carrier rather than the timing of energy use, indicating that their flexibility is primarily related to fuel choice rather than load shifting. Overall, the findings confirm that local-scale cross-vector flexibility—particularly by combining power-to-heat technologies with intelligent control—can significantly lower operational costs, improve renewable integration, and contribute to deep decarbonisation of urban heating systems. We see a high potential for future work to focus on the dynamic operation of such hybrid systems, real-time market participation strategies, and the replication of the approach demonstrated here in other municipalities to accelerate the transition toward climate-neutral and resilient local energy systems. Further refinement of consumer-side flexibility modelling and continued validation against demonstration data would strengthen the applicability of these results.

Funding

All authors are funded by the ENFLATE project, with support from the EU Horizon program, grant agreement 101075783.

Availability of data and materials

Data available on request from the authors.

REFERENCES

1. É. Mata, J. Ottosson, and J. Nilsson, ‘A review of flexibility of residential electricity demand as climate solution in four EU countries’, *Environ. Res. Lett.*, vol. 15, no. 7, p. 073001, July 2020, doi: 10.1088/1748-9326/ab7950.
2. K. Schwab and T. Malleret, *The Global Risks Report 2025 20th Edition*, Edition 1.0. Cologny/Geneva, Switzerland: Forum Publishing, 2022.
3. R. Sinha, B. Bak-Jensen, J. Radhakrishna Pillai, and H. Zareipour, ‘Flexibility from Electric Boiler and Thermal Storage for Multi Energy System Interaction’, *Energies*, vol. 13, no. 1, p. 98, Dec. 2019, doi: 10.3390/en13010098.
4. M. Waite and V. Modi, ‘Potential for increased wind-generated electricity utilization using heat pumps in urban areas’, *Appl. Energy*, vol. 135, pp. 634–642, Dec. 2014, doi: 10.1016/j.apenergy.2014.04.059.
5. P. Meibom, J. Kiviluoma, R. Barth, H. Brand, C. Weber, and H. V. Larsen, ‘Value of electric heat boilers and heat pumps for wind power integration’, *Wind Energy*, vol. 10, no. 4, pp. 321–337, July 2007, doi: 10.1002/we.224.
6. J. Kiviluoma and P. Meibom, ‘Influence of wind power, plug-in electric vehicles, and heat storages on power system investments’, *Energy*, vol. 35, no. 3, pp. 1244–1255, Mar. 2010, doi: 10.1016/j.energy.2009.11.004.
7. Z. Ma, A. Knotzer, J. D. Billanes, and B. N. Jørgensen, ‘A literature review of energy flexibility in district heating with a survey of the stakeholders’ participation’, *Renew. Sustain. Energy Rev.*, vol. 123, p. 109750, May 2020, doi: 10.1016/j.rser.2020.109750.
8. H. Golmohamadi, K. G. Larsen, P. G. Jensen, and I. R. Hasrat, ‘Integration of flexibility potentials of district heating systems into electricity markets: A review’, *Renew. Sustain. Energy Rev.*, vol. 159, p. 112200, May 2022, doi: 10.1016/j.rser.2022.112200.
9. ‘Energiforsk’. [Online]. Available: https://energiforsk.se/program/termiska-energilager/illustrerande-systembilder/
10. E. Nyholm, S. Puranik, É. Mata, M. Odenberger, and F. Johnsson, ‘Demand response potential of electrical space heating in Swedish single-family dwellings’, *Build. Environ.*, vol. 96, pp. 270–282, Feb. 2016, doi: 10.1016/j.buildenv.2015.11.019.

11. L. Hofbauer, W. McDowall, and S. Pye, 'Challenges and opportunities for energy system modelling to foster multi-level governance of energy transitions', *Renew. Sustain. Energy Rev.*, vol. 161, p. 112330, June 2022, doi: 10.1016/j.rser.2022.112330.

12. H. Lund, P. A. Østergaard, M. Yuan, P. Sorknæs, and J. Z. Thellufsen, 'Energy balancing and storage in climate-neutral smart energy systems', *Renew. Sustain. Energy Rev.*, vol. 209, p. 115141, Mar. 2025, doi: 10.1016/j.rser.2024.115141.

13. A. Pesola, 'Cost-optimization model to design and operate hybrid heating systems – Case study of district heating system with decentralized heat pumps in Finland', *Energy*, vol. 281, p. 128241, Oct. 2023, doi: 10.1016/j.energy.2023.128241.

14. G. Reynders, J. Diriken, and D. Saelens, 'Generic characterization method for energy flexibility: Applied to structural thermal storage in residential buildings', *Appl. Energy*, vol. 198, pp. 192–202, July 2017, doi: 10.1016/j.apenergy.2017.04.061.

15. É. Mata, N. P. Garcia, D. Suna, B. Unluturk, A. Jacobson, and O. Lysenko, 'Comparative modeling of cost-optimal energy system flexibility for Swedish and Austrian regions', *Environ. Res. Energy*, vol. 1, no. 1, p. 015004, Mar. 2024, doi: 10.1088/2753-3751/ad3191.

16. M. Dahl, A. Brun, and G. B. Andresen, 'Cost sensitivity of optimal sector-coupled district heating production systems', *Energy*, vol. 166, pp. 624–636, Jan. 2019, doi: 10.1016/j.energy.2018.10.044.

17. D. Romanchenko, M. Odenberger, L. Göransson, and F. Johnsson, 'Impact of electricity price fluctuations on the operation of district heating systems: A case study of district heating in Göteborg, Sweden', *Appl. Energy*, vol. 204, pp. 16–30, Oct. 2017, doi: 10.1016/j.apenergy.2017.06.092.

18. I. Blanco, D. Guericke, A. N. Andersen, and H. Madsen, 'Operational Planning and Bidding for District Heating Systems with Uncertain Renewable Energy Production', *Energies*, vol. 11, no. 12, p. 3310, Nov. 2018, doi: 10.3390/en11123310.

19. C. Andrade, S. Selosse, and N. Maïzi, 'The role of power-to-gas in the integration of variable renewables', *Appl. Energy*, vol. 313, p. 118730, May 2022, doi: https://doi.org/10.1016/j.apenergy.2022.118730.

20. D. Connolly, H. Lund, B. V. Mathiesen, and M. Leahy, 'A review of computer tools for analysing the integration of renewable energy into various energy systems', *Appl. Energy*, vol. 87, no. 4, pp. 1059–1082, Apr. 2010, doi: 10.1016/j.apenergy.2009.09.026.

21. H. Lund *et al.*, 'The status of 4th generation district heating: Research and results', *Energy*, vol. 164, pp. 147–159, Dec. 2018, doi: 10.1016/j.energy.2018.08.206.

22. R. Loulou, G. Goldstein, and K. Noble, *Documentation for the MARKAL Family of Models*. ETSAP, 2004. [Online]. Available: https://iea-etsap.org/MrklDoc-III_SAGE.pdf

23. R. Loulou, U. Remne, A. Kanudia, A. Lehtila, and G. Goldstein, *Documentation for the TIMES Model - Part I*. ETSAP, 2005. [Online]. Available: https://iea-etsap.org/docs/Documentation_for_the_TIMES_Model-Part-I.pdf