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1 Executive Summary

Deliverable D2.3 of the DecarbonDHS project – “Assessment of the potential for integrating other renewable energy sources into the district heating network” – evaluates how diverse renewable energy solutions can be harnessed to decarbonize district heating (DH) systems. This report’s purpose is to provide evidence-based insights into integrating various renewable heat sources into existing DH networks, thereby guiding the transition toward low-carbon, sustainable heating across the partner regions. It builds on collaborative analysis from multiple project partners to identify practical pathways, benefits, and challenges for renewable integration in DH, in line with DecarbonDHS’s mission of reimagining heating networks with minimal fossil fuel reliance.

Structure and Methodology: The deliverable is structured into four chapters: **Chapter 2 (Methodology)** outlines a common approach developed collaboratively by the partners. A unified analytical framework was applied, defining shared metrics (e.g. energy output, CO₂ reduction, economic feasibility) and selection criteria for case studies. This ensured that each partner’s analysis was consistent and comparable. Partners used a cross-country collaborative framework to exchange data and best practices, enabling a robust cross-partner analysis. Each case study follows a standardized format examining the fundamental technology, integration steps and timeline, expected outcomes (such as energy yield and cost savings), identified risks and mitigation measures, impact assessments (including CO₂ emissions reduction, job creation and social acceptance), and policy/regulatory considerations. This structured methodology provides a coherent basis for comparing results across different renewable technologies.

Case Studies (Chapter 3): Six in-depth case studies – contributed by project partners in Poland, Lithuania, Denmark, Germany, and Sweden – explore the integration of various renewable energy sources. These case studies cover: (1) Geothermal energy utilization in a Polish DH system (IMP PAN), demonstrating the use of deep geothermal heat for stable, year-round supply; (2) A large-scale solar thermal farm in Wejherowo, Poland (OPEC), supplying clean solar heat to the local network and offsetting fossil fuels; (4) Wind energy usage for district heating on Bornholm, Denmark (BEOF); (4) Conversion from natural gas to biomass fuel in Kaunas, Lithuania (LEI), where the city’s DH system has transitioned to locally sourced biomass, dramatically reducing gas consumption; (5) Utilization of industrial surplus heat from green hydrogen production (IWEN) in a German case study, capturing waste heat from electrolysis processes to feed the DH grid; and (6) Co-production of biochar in a biomass heating plant in Sweden (LNU), an innovative approach that produces a carbon-rich solid (biochar) for long-term CO₂ sequestration while delivering heat.

Each case study was developed by the respective local partner using real operational data or pilot projects, and analysed under the shared framework. Together, these cases illustrate a broad spectrum of renewable integration options – from mature technologies like biomass and solar thermal to emerging solutions like hydrogen waste heat recovery and biochar-negative-emission systems.

Key Findings and Trends: Across the case studies, several common benefits and challenges were identified. Collective benefits include substantial greenhouse gas emission reductions (each solution replaces or offsets conventional fossil-fuel heat production) and improved energy security through diversification of heat sources. Many solutions also bring positive socio-economic impacts – for example, the biomass transition in Kaunas has leveraged local fuel resources to stabilize heat prices and create local jobs, and the deployment of solar and geothermal projects stimulates regional investment in clean energy. Furthermore, some innovations (such as biochar co-production) offer co-benefits like carbon removal credits, aligning with long-term climate neutrality goals. Common barriers were observed as well. Most renewable integrations require high upfront investments and significant technical adjustments to existing DH infrastructure (e.g. drilling geothermal wells, retrofitting boilers or installing new heat exchangers). Intermittency or variability of certain resources is a challenge – solar and potential wind inputs are seasonal or weather-dependent, and even hydrogen production waste

heat can fluctuate with electrolysis operating schedules – necessitating storage solutions and flexible network management. Regulatory and market hurdles are another recurring theme: for instance, integrating third-party heat sources or new biomass plants into a DH network can be complicated by existing market structures and permitting rules. The need for supportive policies and incentives is highlighted across cases (e.g. clearer frameworks for waste-heat utilization contracts and for biochar carbon credit certification). Ensuring sustainable fuel supply chains (in the biomass and biochar cases) and maintaining public acceptance (for new technologies or land use for renewables) are also crucial factors.

In summary, **Chapter 4 (Conclusions and Recommendations)** synthesizes these insights to underscore that a mix of renewable heat solutions – tailored to local resource availability – can significantly advance the decarbonization of district heating networks. The collaborative analysis in this deliverable shows that while there is no one-size-fits-all solution, each technology offers distinct advantages that, if combined strategically, could enable near-term and cost-effective CO₂ reductions in the DH sector. Realizing this potential will require overcoming the common barriers identified, through coordinated efforts in policy support, investment in infrastructure (e.g. thermal storage, grid upgrades), and knowledge-sharing among DH operators. The findings of Deliverable D2.3 thus provide valuable guidance for policymakers and industry stakeholders, informing the next steps toward sustainable, resilient, and low-carbon district heating systems in the Baltic region and beyond.

2 Methodology

2.1 Overall Approach: Collaborative framework for cross-partner analysis

This deliverable was developed through a coordinated, multi-partner effort involving six main partner organizations across five countries. The project adopted a tandem approach, pairing technical expert partners with local district heating companies or municipalities to work on case studies in their specific contexts. Under the leadership of the work package coordinator, partners jointly defined the evaluation approach and each contributed a case study focusing on a different renewable integration option (e.g. geothermal, solar thermal, biomass, etc.).

A common methodological framework was established at the outset to ensure consistency: all partners agreed on shared analysis goals, used standardized document templates, and followed a harmonized structure for reporting results. Indeed, each case study was documented using the same outline – covering the technology background, site details, integration plan, expected outcomes, challenges, impact assessment, and policy considerations – which enabled direct comparison across cases. Collaboration was facilitated through regular coordination meetings and knowledge-sharing sessions. The consortium held frequent conference calls and several in-person workshops to align on data assumptions and methodological steps, allowing partners to troubleshoot issues and learn from each other's experiences in real time.

For example, interim findings from one pilot (e.g. on integrating waste heat) were discussed with other partners to refine analysis techniques for another pilot. The lead author/editor integrated all contributions into a single report, ensuring a cohesive narrative and cross-checking that each case study's analysis met the agreed standards. This iterative, cross-partner review process helped maintain consistency in quality and depth across the diverse case studies. Furthermore, by working in international teams, partners benefited from cross-border knowledge transfer – exposing each case to external insights and best practices. The collaborative framework thus combined the strengths of all contributors: research institutions provided analytical rigor (e.g. modelling CO₂ impacts or economic performance), while utilities and municipal partners contributed operational data and practical insights from the field.

This structured cooperation and shared methodology ensured that the assessment of renewable options in each district heating case was both locally grounded and comparatively framed at the project level.

2.2 Analytical Frameworks: Shared Metrics

All partners adopted a set of shared metrics and evaluation criteria to assess the performance and feasibility of integrating renewable energy sources into district heating. This common analytical framework spanned several key dimensions:

- **Environmental Impact:** Each case study quantified potential greenhouse gas reductions, primarily focusing on CO₂ emissions abatement relative to the existing fossil-fuel baseline. All partners treated CO₂ reduction as a core indicator of success, directly reflecting the project's decarbonization objectives.
- **Technical Performance and Feasibility:** Metrics such as energy output delivered, percentage of heat demand covered by the renewable source, and system reliability were evaluated. A common concern was system integration feasibility – i.e. how well the new source could be technically and operationally integrated into the existing heating network. Each case study outlined the required infrastructure and control adaptations and gauged any constraints (e.g. temperature compatibility

or resource intermittency). Scalability and replicability of the solution were also assessed: partners examined whether the approach could be scaled up or repeated in other locations.

- **Economic Criteria (CAPEX/OPEX and Financial Viability):** All case studies considered financial metrics to ensure the solutions are economically viable. Capital expenditures (CAPEX) and operational expenditures (OPEX) were estimated for each technology option, often using common data sources or assumptions for consistency. Partners evaluated indicators like heat production cost, expected fuel savings, and impacts on consumer heat prices. By using these shared economic metrics, the consortium could compare the cost-effectiveness of different renewable integrations, even if absolute numbers differed by case.
- **Social and Policy Factors:** Qualitative metrics around social acceptance and wider socio-economic benefits were included in each evaluation. Each partner assessed how the local community and stakeholders perceive the project – for instance, whether there is public support or any notable opposition (as might be the case for visible infrastructure like wind turbines or changes in fuel use). Many case studies highlighted co-benefits to bolster social acceptance, such as improved local air quality and public health (by reducing fossil fuel pollution) and enhanced energy security or price stability for the community. Additionally, job creation and local economic impact were tracked: projects reported temporary jobs during construction and permanent jobs in operation/maintenance where relevant.

2.3 Case Study Selection Criteria: Rationale for partner-specific technologies

Geothermal energy use in Podhale region: Geothermal energy is an ecological and sustainable renewable energy source with enormous potential. It has wide possibilities of use and is characterized by reliable and stable energy production, independent of weather conditions. It can be used for a range of purposes such as to generate electricity (for high temperature heat sources) or most often it provides direct heat for district heating (and cooling), water heating, industrial processes or greenhouse food production and fish breeding.

An example of the extensive use of geothermal energy in heating is a project implemented in Poland involving the use of geothermal waters in a heating system supplying heat to consumers in 4 municipalities in the Podhale region. The system is operated by the heating company Geotermia Podhalańska SA and is based on the use of six geothermal wells with a maximum temperature of 86°C. The heating network, with a total length of over 118 km, currently supplies heat to approximately 1,870 buildings. Thermal energy from geothermal production currently covers 99% of the customers' heating needs. The customers' contracted capacity is 82 MW, and their annual heat consumption is approximately 533 TJ. Currently, the geothermal heating system contributes to an annual reduction of CO₂ emissions by over 50,000 tons.

PEC Geotermia Podhalańska's results confirm that investing in geothermal energy is economically viable. Heat prices from the geothermal heating network are now highly competitive compared to natural gas, heating oil, and electricity used to heat buildings. The company's stable pricing policy and reliable energy supply mean that more and more customers are expressing interest in connecting to the geothermal heating network.

Solar thermal energy use in Wejherowo: The solar farm is part of the Wejherowo heating plant's energy mix which aims to phase out coal combustion. A daily heat storage system will work with the solar farm, ensuring flexible heat use 24/7. Using the solar farm as a renewable energy source will enable the Wejherowo heating plant to achieve energy efficiency status. It's important to note that the solar farm is the most ecological heat source, using only sunlight and zero emissions. The Wejherowo heating plant's energy mix also includes a biomass boiler, an electrode boiler, and gas-oil boilers.

Wind Energy Integration in Bornholm: BEOF's district heating system in Hasle produced approximately 55 GWh of heat in 2024, primarily from biomass sources such as straw and wood chips. While this approach has supported renewable heat delivery, rising fuel costs and aging infrastructure pose long-term challenges. At the same time, the area near the district heating grid in Hasle hosts Vystebby Wind Park, generating around 15 GWh annually, much of which is curtailed or sold at low prices during periods of surplus. Integrating wind energy into the Hasle district heating network through electric boilers and CO₂-based heat pumps offers a pathway to electrify heat production, reduce biomass dependency, and enhance grid flexibility. This sector-coupling strategy not only leverages existing renewable assets but also enables thermal storage to absorb excess wind power, mitigating curtailment and supporting Denmark's 2050 fossil-free target. Given its potential to deliver cost savings, CO₂ reductions, and system resilience, this case study examines the technical and economic feasibility of wind-powered district heating on Bornholm.

Transfer from natural gas to biomass in Kaunas: Till 2012 Kaunas DH company "Kauno Energija" used to purchase more than 80 percent of the heat required by the city from the Kaunas cogeneration plant owned by Russia's Gazprom, as stipulated in the contracts, and after Gazprom sold the power plant to a minority shareholder, the obligations to purchase a certain amount of heat were no longer applied. With the prices for natural gas constantly growing drastically, cheaper indigenous opportunities were investigated.

In order to reduce the use of fossil fuels (natural gas) in heat production, in 2012 Kauno Energija began investing in the construction of biomass-fired heating boilers. With the support of the European Union Structural Funds and the Lithuanian Environmental Investment Fund, Kauno Energija has invested more than €5.38 million in the construction of biofuel boiler houses over the few years. This has allowed the share of heat produced from renewable energy sources to increase from 11% to 90%. The company operates 450 km network, supplies to over 125,000 consumers, generates and provides heating, cooling, and hot water to their consumers. The total installed thermal capacity of the Company is approximately 520.6 MW (of which 52.9 MW is condensing economizers and 3.1 MW is absorption heat pumps), and 8.75 MW of electrical capacity). In order to meet consumer demand for heat, Kauno energija purchases heat from independent heat producers in accordance with the procedure established by law. There are 11 such producers operating in Kaunas and the Kaunas district, which are all burning biomass and municipal solid waste (MSW). Since 2012, the heat price in Kauno energija has reduced by 57.24%.

One of the objectives of Lithuania's national energy strategy is to achieve CO₂-free heat production by 2050. Kauno Energija is actively contributing to this goal by implementing less polluting technologies and applying preventive measures.

Biochar use in Kosta: Sweden's district heating sector used approximately 60.6 TWh of input energy in 2022, of which biomass supplied 39.8 TWh (66%). With a total delivered heat output of 55.4 TWh, the sector already operates at a high average efficiency of about 91%, and biomass-fired systems can be considered nearly carbon-neutral [1]. Despite this strong foundation, polygeneration offers an opportunity to further strengthen system-wide decarbonization. Integrating biochar production into existing biomass-fired district heating plants introduces a complementary pathway that not only maintains renewable heat delivery but also provides long-term carbon sequestration and agronomic benefits through soil enhancement. Given its potential to unlock additional environmental value without compromising core heat services, biochar co-production merits deeper investigation as a case study for the Swedish context within this report.

Waste heat usage from H₂ electrolysis in Rostock: Analyzing the waste heat from the planned electrolyser plant in the Port of Rostock is essential because electrolysis processes inherently generate significant amounts of low-temperature thermal energy as a by-product of hydrogen production. Capturing and utilizing this waste heat—for example by integrating it into the local district heating network—can substantially improve the overall energy efficiency and economics of green hydrogen production, reducing both operational costs and lifecycle emissions. In the specific context of Rostock, this rationale is amplified by the region’s strategic development as a major hydrogen hub: the HyTech Hafen Rostock project and the broader Rostock Energy Port concept aim to leverage abundant renewable electricity from Baltic wind and solar resources to produce green hydrogen at industrial scale, with plans to expand electrolysis capacity toward gigawatt levels by 2030. Surplus thermal energy from these electrolysers can be fed into existing urban energy systems, supporting local heating needs while strengthening sector coupling between electricity, heat, and hydrogen infrastructures. This integration aligns with initiatives by the Rostock Hydrogen Initiative to position the port and surrounding region as a competitive node in Germany’s and Europe’s emerging hydrogen economy, where efficient use of all energy streams—including waste heat—will be key to economic viability and decarbonization goals.

3 Case Studies

3.1 IMP PAN: Geothermal energy

3.1.1 Fundamental Technology

Geothermal energy is heat energy from the Earth's interior, found in rocks, water, and ground beneath the surface.

Due to its origin, it is available all year round and is not dependent on climatic factors. It is a renewable energy source that can be used for a range of purposes such as to generate electricity or provide direct heat for district heating, water heating, industrial processes or greenhouse food production and fish breeding.

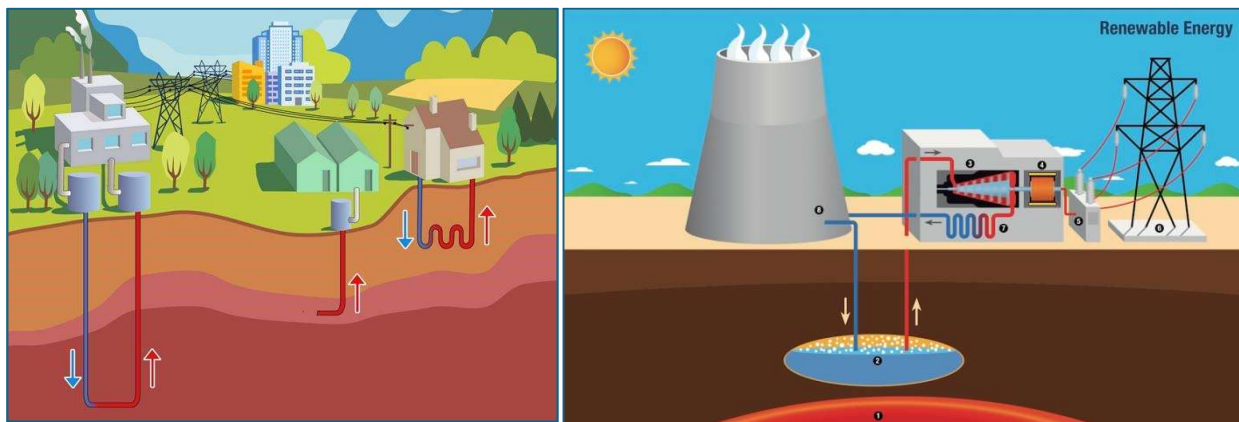


Figure 3.1: Simplified diagrams illustrating the use of geothermal energy [2, 3].

Advantages of using geothermal energy

- Ecological energy source (environmentally friendly energy - minimal carbon footprint).
- Renewable and sustainable source (geothermal reservoirs come from natural resources and are naturally replenished).
- Source with huge potential (potential estimates - from 0.035 to 2 TW).
- Low operating costs and long durability.
- Reliability and stability of energy production (independent of climatic conditions; high efficiency coefficient).
- Wide possibilities of use.

Geothermal use and technologies

In terms of geothermal gradients, the resources are divided into shallow geothermal, middle deep geothermal and deep geothermal. This determines the temperature available, as on average it increases by about 25 °C for every kilometre of depth.

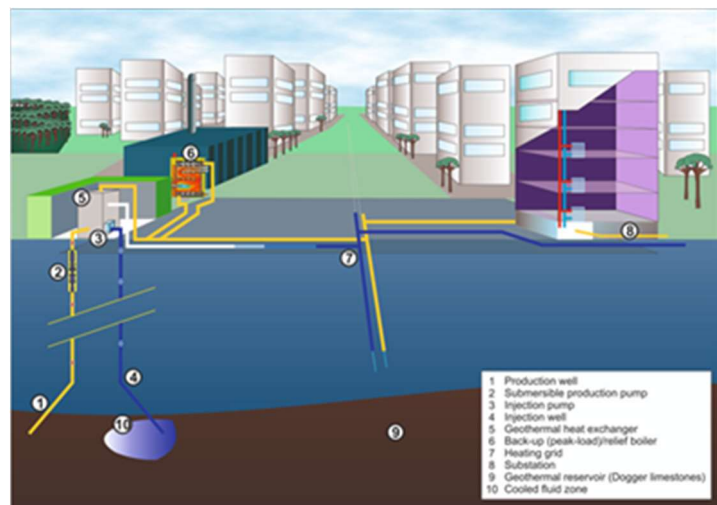
Temperatures between 40 °C and 150 °C are ideal for district heating. For electricity generation, medium-to high temperature resources are needed (Table 3.1).

Table 3.1: Possibilities of using geothermal sources with different temperature ranges and the technologies used [4].

Temperature	Fluid type	Application	Technology
High (>150°C)	Water, vapour	Electricity generation District heat use	Dry steam, flash plants Heat exchanger
Medium (90-150°C)	Water	Electricity generation District heat use	Binary cycle Heat exchanger, heat pump
Low (<90°C)	Water	District heat use	Heat exchanger, heat pump, direct heat use

Geothermal district heating systems typically consist of a central heat production facility, a network of pipes for heat distribution, and individual heat exchangers in buildings. Heat is extracted from the ground using heat pumps or other geothermal technologies. Some systems using shallow geothermal resources operate on large heat pumps able to increase temperatures beyond 80 °C, thus expanding potential uses beyond residential heating.

Generating electricity from geothermal energy involves using heat stored beneath the Earth's surface and use fluids from underground reservoirs to produce steam, which then drives turbines to generate electricity. The three main types of geothermal technologies are dry steam, flash steam and binary cycle.

**Figure 3.2: Main components of geothermal district heating system.**

Geothermal energy in numbers

In 2021, 88 countries in the world operated systems with direct use of geothermal energy, while 29 countries produced electricity using geothermal resources. In 2022, 142 geothermal power plants were operating in Europe with a total installed capacity of around 3.5 GW_e, generating over 22 TWh/year of electricity. The installed capacity of geothermal heating from medium and low temperature sources exceeded 11.6 GW_{th}, of which about half is used in heating.

In 2022, 395 geothermal heating and cooling systems were operating in Europe, including 261 in EU. The total installed capacity of geothermal heating and cooling systems in Europe at the end of 2022 was around 5.6 GW_{th}.

Geothermal energy in heating systems

Most European countries use geothermal energy to produce heat. This is mainly determined by the temperature of the available resources. By the end of 2023, 401 geothermal DHC systems were operating

in Europe, of which 298 were in EU Member States. Geothermal energy is used for heating and cooling buildings, and the installed capacity for this purpose is much higher than for electricity generation.

Top countries: Sweden, Germany, and Finland are the leading European countries in terms of geothermal district heating and cooling capacity.

3.1.2 Case study details

This case study focuses on a project involving the use of geothermal energy in the Podhale region, implemented in Poland by PEC Geotermia Podhalańska S.A. PEC Geotermia Podhalańska S.A. is a joint-stock company based in Zakopane.

The company's shareholders are:

- National and Provincial Funds for Environmental Protection and Water Management (totalling approximately 93% of shares)
- City of Zakopane (6% of shares) and City of Nowy Targ
- Municipalities: Szaflary, Poronin, Kościelisko and Bukowina Tatrzańska
- Institute of Mineral Resources and Energy Management of the Polish Academy of Sciences in Kraków (IGSMiE PAN)
- Tatrzańska Komunalna Grupa Kapitałowa Sp. z o.o. and individuals.

The company's mission is to utilize renewable energy sources contained in geothermal waters for the following purposes:

- central heating and domestic hot water preparation
- air conditioning
- tourism and recreation
- balneology.

The project is being carried out in the Podhale Basin, an important reservoir of thermal waters. At a depth of approximately 1000 m, in Zakopane, the water temperature is approximately 26°C, while at depths below 2000 m, in the Biały Dunajec and Bańska areas, it reaches temperatures above 80°C. Between 10 boreholes were drilled in Podhale between 1981 and 1997. All boreholes revealed the presence of geothermal waters with a maximum temperature of 86°C and a flow rate of up to 550 m³/h. Their significant advantage compared to waters extracted in other regions of Poland is their very low mineralization and the fact that they flow to the surface under their own pressure (with the exception of the borehole located on Furmanowa Peak and in Bukowina Tatrzańska).

The Institute of Mineral Resources and Energy Management (IGSMiE) was a pioneer in harnessing energy from the Earth's interior. Between 1989 and 1993, the first Polish Academy of Sciences Geothermal Experimental Plant was designed and commissioned in Bańska Niżna. The first few buildings were connected to the geothermal heating network, with heat production based on two wells: Bańska IG-1 and Biały Dunajec PAN-1. Based on this experience, a commercial project was subsequently developed. In 1994, a pilot heating installation was launched and expanded over time. The process of expansion and connecting new customers is ongoing and is carried out by PEC Geotermia Podhalańska S.A., a heat producer and distributor.

Geotermia Podhalańska S.A. is currently the largest heat producer in Poland utilizing the ecological energy of geothermal water. Currently, the PEC Geotermia Podhalańska S.A. heating network covers four municipalities: Zakopane, Szaflary, Biały Dunajec, and Poronin. The company has a strong position in the local heating market, which is based on competitive prices, secure supply, and high-quality customer service standards. Heat sales in 2023 amounted to 533,560 GJ, with 1,588 heat customers and 1,904 facilities connected to the network. The commissioned capacity increased to 82,193 MW. In 2023, 99.01% of heat demand was met by geothermal production, with the remaining demand covered by gas boilers (0.27%) and an oil boiler (0.72%).

3.1.3 Integration plan – technical steps and timeline

Table 3.2: Project implementation stages.

Stage Number	Implementation Period	Project Scope
I	1993-1994	<ol style="list-style-type: none"> 1. Establishment of Geotermia Podhalańska S.A. 2. Launch of the pilot phase of the project entitled "Heat Supply to the Village of Bańska Niżna" as the first operational geothermal installation in Poland.
II	1995-1996	<ol style="list-style-type: none"> 1. Construction of a distribution network in Biały Dunajec and connection of 27 households to the network. 2. Commencement of construction of a geothermal heating plant in Bańska Niżna.
III	1997-1998	<ol style="list-style-type: none"> 1. Completion of drilling of the Biały Dunajec PGP-2 and Bańska PGP-1 wells. 2. Establishment of the Thermal Energy Company Geotermia Podhalańska S.A. 3. Commissioning of the Peak Load Boiler Plant in Zakopane.
IV	2001-2002	<ol style="list-style-type: none"> 1. Completion of the construction of the heating network: Bańska Niżna – Peak Boiler House Zakopane and the Bańska Geothermal Heating Plant, and the launch of heat supplies from boreholes in Bańska Niżna. 2. Expansion of the heating network and connection of new customers in Zakopane and the municipalities of Biały Dunajec and Poronin. 3. Commissioning of three gas engines with a total capacity of 1.5 MW_{el} and 2.1 MW_{th} in the Peak Boiler House.
V	2012-2013	<ol style="list-style-type: none"> 1. Completion of the project to expand the district heating networks in the municipalities of Zakopane, Biały Dunajec, and Szaflary. 2. Completion of drilling of the Bańska PGP-3 production well.
VI	2020-2021	<ol style="list-style-type: none"> 1. Completion of drilling of the PGP-5 injection well. 2. Reconstruction and deepening of the PGP-2 injection well.
VII	2022	Expansion of the Geothermal Heating Plant and installation of 4 new heat exchangers.

VIII	2023-2024	<ol style="list-style-type: none"> 1. Exceeding the 80 MW capacity ordered by customers and 530,000 GJ of heat sales. 2. Commencement of the project entitled "Expansion of the geothermal system by drilling a new production well, Bańska PGP-7, delivery and installation of heat exchangers at the Geothermal Heating Plant, and construction of connections and heating networks to increase capacity and utilize renewable energy sources."
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Development of heat production and distribution infrastructure

From 1995 to 2022, PEC Geotermia Podhalańska S.A. invested a total of PLN 345.4 million in the development of heat production and distribution infrastructure, using its own funds and domestic and foreign aid. Thanks to these funds, significant investments were made in virtually all areas of the company's operations. The most important achievements in recent years include:

- Modernization and expansion of the Bańska Niżna Geothermal Heating Plant, including the delivery and installation of four 7.8 MW heat exchangers each and a transformer station.
- Drilling of a new Biały Dunajec PGP-5 injection well to a depth of 3,272.1 m TVD (3,564.0 m MD) with a capacity of 800 m³/h.
- Deepening and reconstruction of the Biały Dunajec PGP-2 injection well to a depth of 2,793.0 m TVD (2,800.0 m MD) along with the construction of an injection pipeline.
- Acidizing (intensified production treatment) of the Bańska PGP-3 production well and increasing the well's capacity from 250 m³/h to 400 m³/h.
- Modernization of the booster pumps at the Geothermal Heating Plant, modernization of the injection pumps and filters at the Biały Dunajec geothermal pumping station, modernization of valves at the Biały Dunajec PGP-2 and Biały Dunajec PAN-1 wellheads, modernization of geothermal pipelines.
- Connecting a total of 461 buildings in Zakopane, Poronin, Biały Dunajec, and Bańska Niżna to the grid between 2016 and 2022, with a total ordered capacity of over 20 MW.

The diagram of the PEC Geotermia Podhalańska S.A. heating system based on geothermal sources is shown in Figure 3.3:

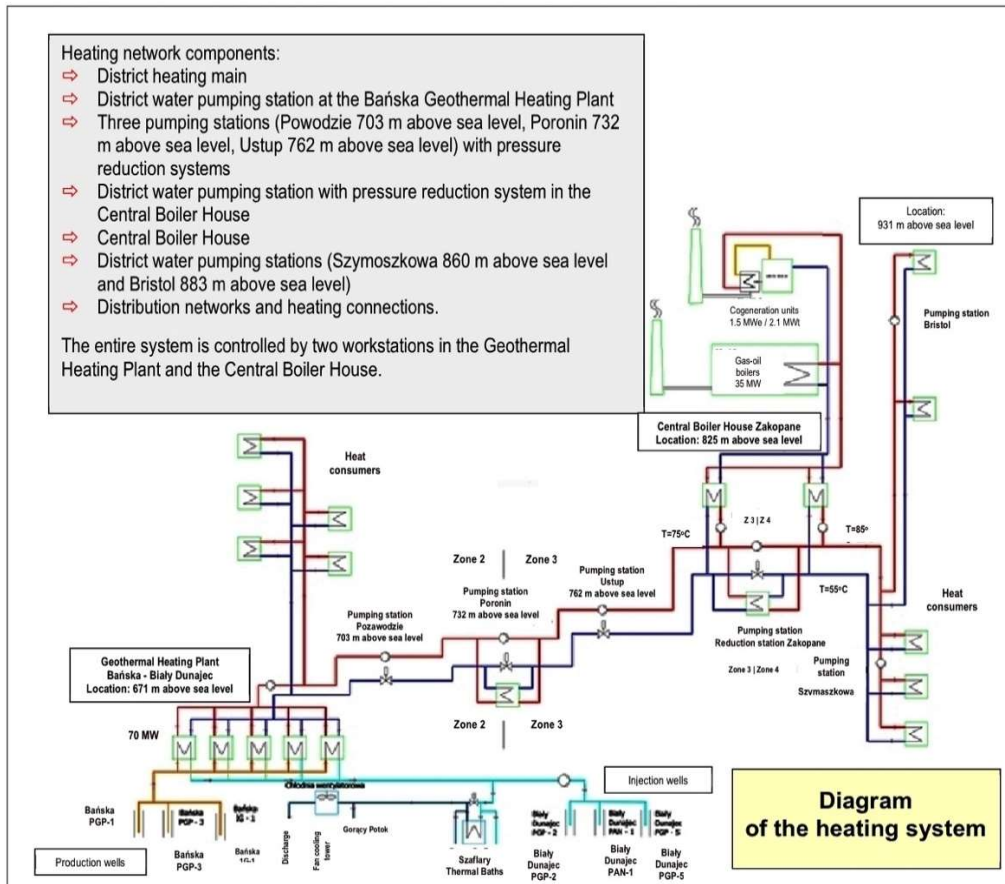


Figure 3.3: Diagram of the PEC Geotermia Podhalańska S.A. heating system based on geothermal sources.

3.1.4 Results achieved

Geothermal System

The current geothermal system consists of production wells (Bańska IG-1, Bańska PGP-1, Bańska PGP-3) and absorption wells (Biały Dunajec PGP-2, Biały Dunajec PAN-1, Biały Dunajec PGP-5), a geothermal pumping station, and cooling towers.

Thermal water is extracted from the deposit through production wells and then heated by plate heat exchangers installed in the Geothermal Heating Plant. The extracted heat is used to heat buildings, swimming pools, and domestic hot water. After extracting the thermal energy, the thermal water is pumped through absorption wells into the deposit, partially cooled, and discharged into a surface stream. A certain amount of the return water is directed to the Szaflary and Gorący Potok recreation and relaxation facilities – here, it is used not only to heat buildings but also to supply the swimming pools.

Heating Network

The PEC Geotermia Podhalańska S.A. heating network is constructed entirely of pre-insulated pipes, with a total length of over 118 km. The district heating system is designed for a nominal pressure of 16 bar. Due to the significant differences in ground elevation, the system has been divided into four pressure zones.

Heat Consumers

District heat consumers are equipped with compact heating substations, including plate heat exchangers. They also feature weather-compensated systems with programmable functions, such as night-time temperature reduction and outdoor temperature adjustment. Plate heat exchangers are characterized by their small size relative to the heat exchange surface area and high thermal conductivity. They are durable, corrosion-resistant, and easy to operate.

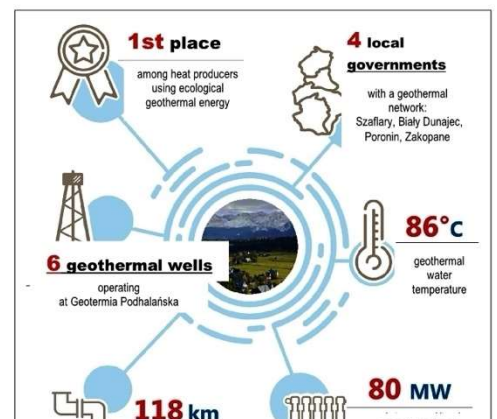
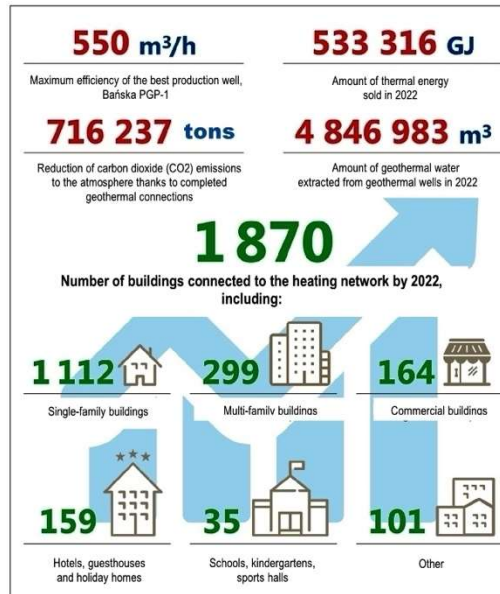


Figure 3.4: Main results achieved as a result of the project implementation.

3.1.5 Challenges

1. High initial investment costs (estimated costs of installing a geothermal power plant with a capacity of 1 MW - 2.5-5 million euros, high drilling costs accounting for half of the total investment costs).
2. Difficulties in locating suitable sites (only selected countries have large resources; transporting geo-thermal energy using hot water generates significant heat losses).
3. Efficiency and long-term exploitation issues (depletion of intensively exploited deposits, need for sustainable exploitation of deposits e.g. through water reinjection systems, require intensive maintenance).
4. Environmental impact and social concerns (risk of groundwater contamination, greenhouse gas emissions such as sulfur dioxide or methane, which can emerge from deep underground).
5. Surface instability (impact on ground stability – surface subsidence, earthquakes).
6. Changing economic and political conditions (susceptibility to changes in energy and economic policy).
7. Technological challenges related to drilling depth (requires advanced technologies).
8. The process of obtaining building permits can be time-consuming and requires compliance with numerous legal standards.

In the case of Geotermia Podhalańska, the following issues and threats were reported:

1. Significant expenses related to injecting geothermal water and maintaining the infrastructure.
2. The significant impact of changes in the prices of other energy carriers on the company's heating service fees (Geotermia Podhalańska was forced to increase heating prices by approximately 22% in December 2022 due to the increase in the prices of other energy carriers).

3.1.6 Impact assessment

Ecological effects

Through its activities, including connecting new heat customers to the district heating network each year, the company contributes to improving the natural environment. Replacing the combustion of fossil fuels with clean geothermal energy reduces dust and gas emissions, while preserving the natural, scenic, and tourist values of Podhale.

Reducing dust and gas emissions associated with the combustion of fossil fuels, such as carbon dioxide, sulfur dioxide, and particulate matter, is particularly important in Podhale, one of the most popular tourist regions in Poland, home to four national parks.

Figure 3.5 and Figure 3.7 show the environmental benefits achieved through the expansion of the geothermal network and connecting new customers.

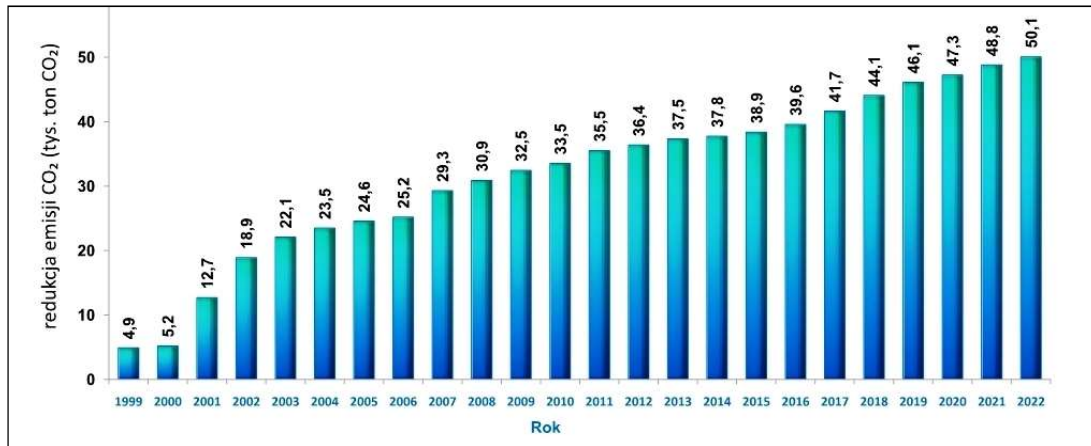


Figure 3.5: CO₂ emission reduction from 1999 to 2022 as a result of the operation of the Geotermia Podhalańska heating system (in thousands of tons of CO₂ per year).

Currently, the geothermal heating system contributes to an annual reduction of CO₂ emissions by over 50,000 tons. Over the 30 years of operation, PEC Geotermia Podhalańska has reduced CO₂ emissions by 716,000 tons. During this time, the annual CO₂ emission reduction has increased more than nine-fold.

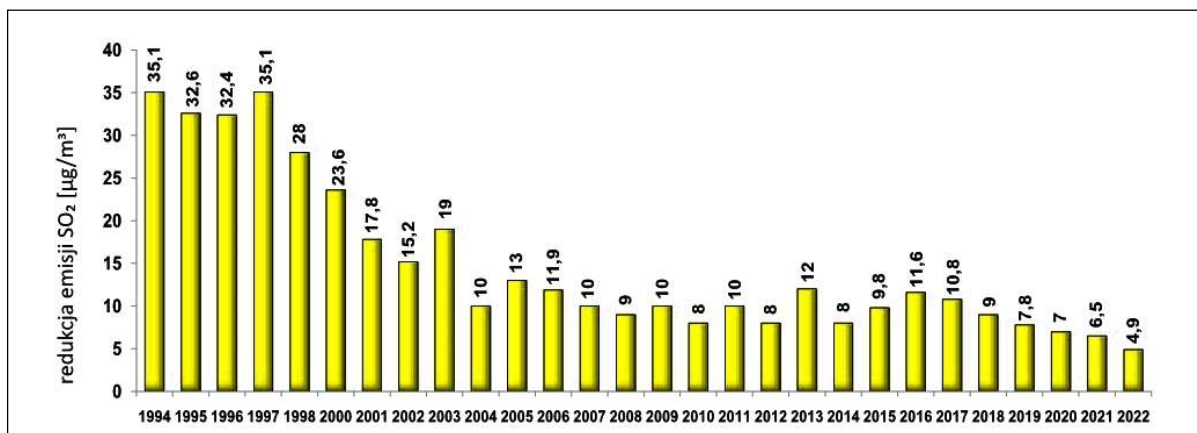


Figure 3.6: SO₂ emission reduction from 1994 to 2022 as a result of the operation of the Geotermia Podhalańska heating system (based on measurements from the Chief Inspectorate of Environmental Protection station in Zakopane).

The average annual SO₂ concentration in 1994-1998 (before the geothermal project commenced) was 32.6 g/m³. In subsequent years, thanks to the connection of new customers to the district heating network, air quality improved. Between 2004 and 2018, the average annual SO₂ concentration ranged from 8 to 13 g/m³, representing an improvement of approximately 68% compared to the period before the geothermal project commenced.

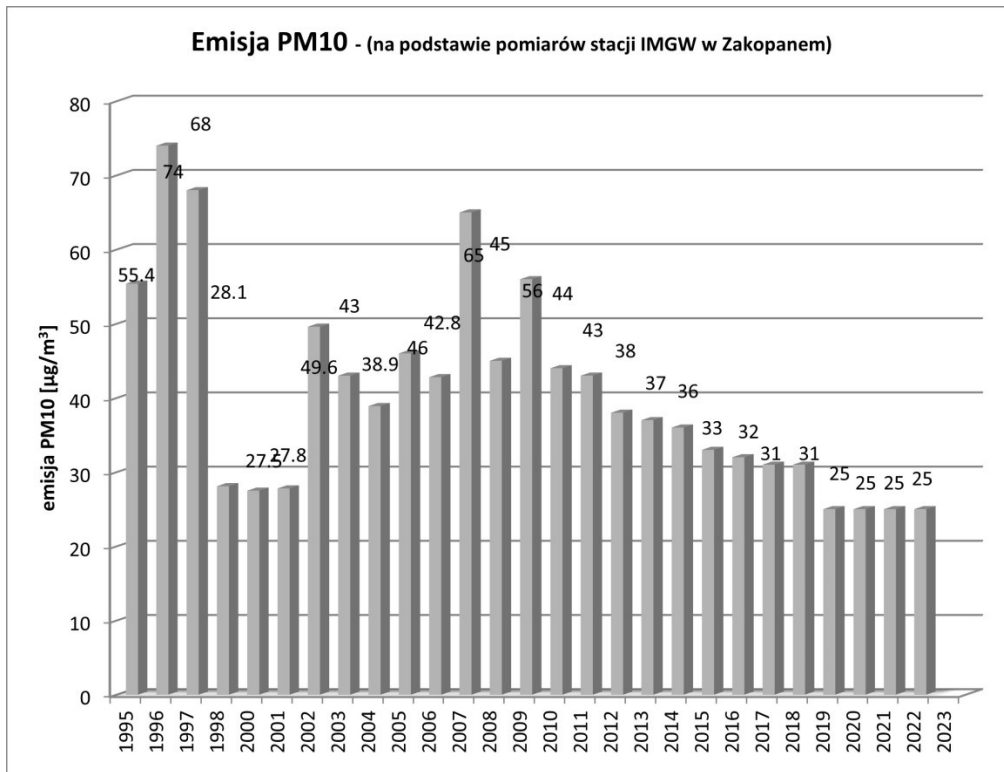


Figure 3.7: PM10 emissions - based on measurements from the Chief Inspectorate of Environmental Protection station in Zakopane.

The average annual PM10 concentration in 1994-1998 (before the geothermal project commenced) was 54.3 g/m³. In the years 2000-2018, the average annual concentration of PM10 was 40.3 g/m³, and the exceptionally high concentrations observed in 2007 and 2009 may be caused by increasing vehicle traffic and secondary dusting, which causes an increase in the density of particulate matter in the air.

Social acceptance

Heat prices from the geothermal heating network are now highly competitive compared to natural gas, heating oil, and electricity used to heat buildings. The geothermal project not only benefits the environment but also offers a favourable economic alternative for the residents of the Podhale region. The company's results confirm that investing in geothermal energy is also economically viable. The company's stable pricing policy and reliability mean that more and more customers are expressing interest in connecting to the heating network.

3.1.7 Policy and Regulatory Consideration

Geotermia Podhalańska's investments are co-financed by the National Fund for Environmental Protection and Water Management and EU funds, which is in line with the assumptions of the European Green Deal and the country's low-emission development strategy.

Geothermal energy holds enormous potential in combating climate change. As technology advances and installation costs decline, we can expect geothermal energy to play an increasingly important role in the global energy mix. Support from governments and financial institutions is crucial for geothermal development. Policies promoting renewable energy sources, such as subsidies, tax breaks, and financing programs, can significantly accelerate the implementation of geothermal systems. As countries strive to meet their climate goals, we can expect support for geothermal energy to increase.

3.2 OPEC: Solar Thermal Farm in Wejherowo

3.2.1 Introduction: Background and Objective

The project involves a 2.5 MW solar thermal farm integrated into the existing district heating (DH) network in Wejherowo, Poland. The primary goals are to reduce the consumption of fossil fuels and enable local, clean heat production. Solar thermal energy is seen as a key component in supporting the decarbonisation of the District Heating System (DHS). The specific objective is the successful integration of solar collectors into the DH network using solar thermal collectors with seasonal variation technology [5].



Figure 3.8: Location: Staromłyńska 41, Wejherowo, Poland.

3.2.2 Fundamental Technology: Principles, maturity, and application in DH

Solar thermal collectors capture solar radiation and convert it into thermal energy, which is then used to heat the working fluid. In this case, the fluid type is Propylene glycol. The system is designed for a Thermal Capacity of 2.5 MW_{th} and an estimated Annual Energy Output of over 5,000 GJ [5]. This technology directly contributes to the decarbonisation of District Heating by displacing heat generated from fossil fuels, offering a highly mature, reliable, and well-established solution for medium to large-scale heat provision.

Table 3.3: Key Technical Specifications.

Parameter	Specification/Details	Source
Technology	Solar Thermal Collectors with Seasonal Variation	Internal OPEC PFU [5]

Thermal Capacity	2.5 MW _{th}	Design Specification
Annual Energy	>5,000 GJ	Feasibility Study Output
Fluid Type	Propylene glycol	System Safety Standard
Mounting Structure	Steel/Aluminium, ground-based	Construction Plan
Tilt Angle	15° – 40°	Optimised for annual yield
Control System	SCADA-ready, local automation	Automation Design [6]

3.2.3 Case Study Details: Location, Design, Capacity and Stakeholders

The project is executed for the client Okręgowe Przedsiębiorstwo Energetyki Ciepłej Spółka z o.o. (OPEC).

- Project Location: Staromłyńska 41, Wejherowo, Poland.
- Client Address: Opata Hackiego 14, 81-213 Gdynia, Poland.
- Site Area: The farm occupies 6,450 m², which represents 36% of the total land area across five parcels (146/6, 146/13, 145/13, 145/14, 145/20). The registration district is 8 [5].
- Infrastructure Connection: The connection distance of the pipeline to the Nanice Combined Heat and Power (CHP) plant is a short 120 meters, minimizing transmission losses.

3.2.4 Integration Plan: Technical steps, infrastructure requirements, timeline

The integration involves connecting the solar thermal system into the existing DH network via a dedicated pipeline and a heat exchanger station.

Key Components in the Hydraulic Setup:

1. Solar Collectors (Solar Field).
2. Primary Circulation Pumps (Glycol Circuit).
3. Glycol-to-Network Water Intermediate Exchanger (Heat Transfer Point).
4. Control Valves to regulate flow into the DH network.

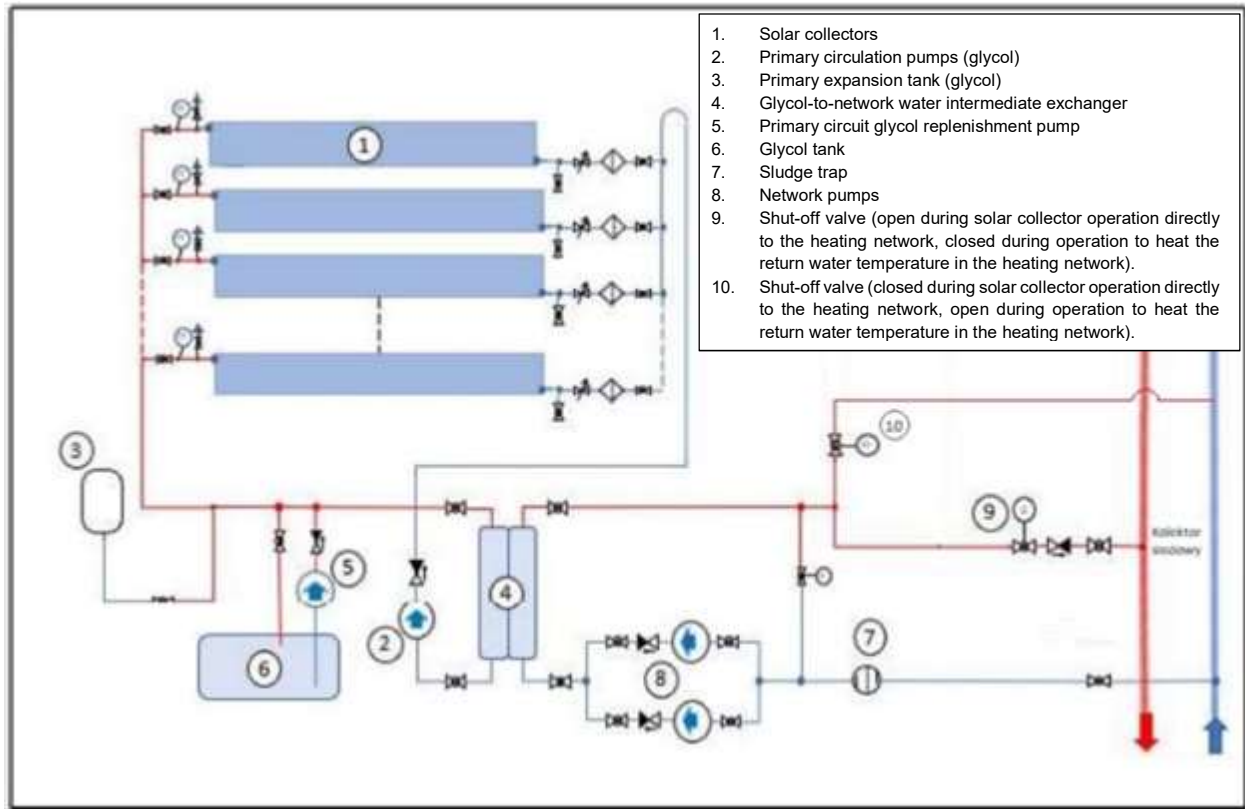


Figure 3.9: Solar farm technology system.

Integration Steps and Planning:

1. Geotechnical Study and Detailed Design: Confirming optimal foundation type (e.g., screw piles due to potential ground instability) and finalising hydraulic schematics.
2. Infrastructure Installation: Construction of the collector frame, pipe connection to the CHP, and installation of the intermediate heat exchanger.
3. System Automation and Commissioning: Installation of sensors and SCADA integration for remote monitoring, fault detection, and real-time output optimisation [6].

Timeline:

- Permitting and Formal Approvals: Q3–Q4 2025.
- Construction and Commissioning: Q1–Q3 2026.
- Target Operational Date: Q4 2026.

3.2.5 Expectations: Predicted energy output, cost savings, scalability

The project is expected to deliver a reliable Thermal Output of 5,000 GJ/year, generating a significant amount of clean heat for the Wejherowo network [5]. By using a stable, free solar resource, the project shields the covered thermal load from fossil fuel price volatility, leading to an expected decrease in district heating costs for residents in the long term. This modular design is easily replicable and scalable, serving as a template for other similar-sized towns in the region looking to integrate solar thermal into their DHS.

3.2.6 Challenges: Risks and Mitigation

Table 3.4: The implementation faces several key challenges related to the site and integration.

Challenge	Detail	Mitigation Strategy
Limited Land Availability	Restricted usable space at the Nanice CHP site requires a compact design.	Efficient collector layout (6,450 m ²) across five coordinated parcels, requiring securing land access and potential new access road [5].
Ground Conditions	Uncertainty regarding subsurface structure (potential instability).	Geotechnical survey to determine soil load-bearing capacity; using screw or driven piles as a flexible foundation alternative to concrete [7].
Weather Variability	Fluctuations in solar radiation impacting output reliability.	System sizing based on NREL Global Horizontal Irradiance (GHI) data [8]; thermal backup guaranteed through hybrid integration with existing CHP sources.
System Integration	Ensuring smooth hydraulic and control compatibility with the current DH network.	Use of plate heat exchangers and a SCADA-ready control system [6] to manage flow and temperature differentials remotely.
Noise and Environmental Impact	Potential noise from pumps/valves and visual impact.	Use of low-noise components (<45 dB at night) and physical shielding (fencing, vegetation) to minimise visual and acoustic impact [5].

3.2.7 Impact Assessment: CO₂ reduction, job creation, social acceptance

The project is designed to deliver significant environmental and social benefits:

- **CO₂ Reduction:** The annual clean heat output is projected to result in CO₂ savings of approximately 350–400 tonnes per year. This is calculated based on the displacement of average CO₂ emissions from hard coal heat production (approx. 94 kg CO₂/GJ) [9].

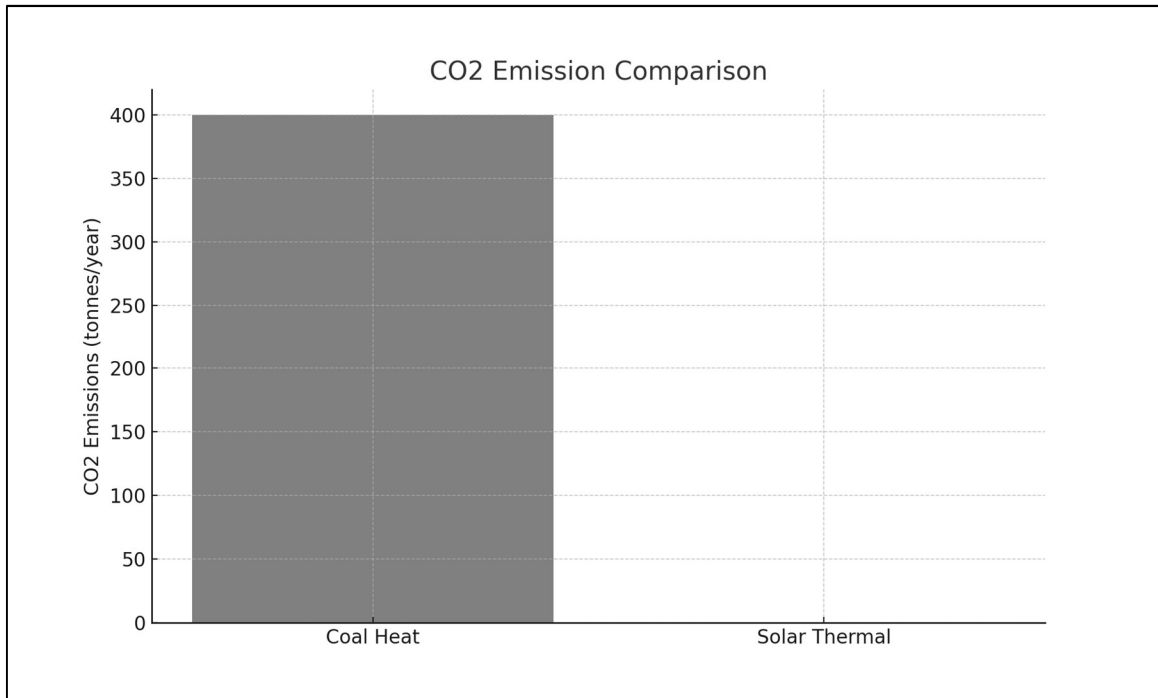


Figure 3.10: CO₂ Emission Comparison Chart.

- **Public Health and Environment:** The farm eliminates combustion-related air pollution for the thermal load it covers, thereby reducing the exposure of the community to particulate matter (PM10, PM2.5) from fossil fuels.
- **Community Benefits:** It enhances energy security for the residents of Wejherowo, increases public awareness of clean energy, and is expected to offer stable, long-term heat pricing.
- **Employment and Local Economy:** The project will create temporary jobs during the construction, planning, and commissioning phases, as well as long-term roles in maintenance, automation, and monitoring.
- **Strategic Role:** The project serves as a crucial demonstration site for the replicable integration of solar thermal technology and is a key part of OPEC's broader decarbonisation strategy, supporting the future expansion of a SCADA-based smart grid (Project SYNERGIA) [6].

3.2.8 Policy and Regulatory Considerations

The project is fully aligned with both European and Polish regulatory frameworks:

- **EU Framework:** Alignment with the EU Renewable Energy Directive (RED II, Directive 2018/2001) [10] and the goals of the European Green Deal and the Fit for 55 package.
- **Polish Legislation:** Full compliance with the Ustawa o Odnawialnych Źródłach Energii (OZE - Renewable Energy Sources Act) [11], as well as all environmental and construction requirements.
- **Permitting:** Formal approvals and urban planning compliance have been secured (as per PFU) [5]. The project also ensures CE conformity for all technical components used.

3.3 BEOF: Wind energy

This case study explores how wind energy can be effectively integrated into a district heating (DH) system using an analysis completed by the Danish utility company on Bornholm Energy and Utility (BEU) as a demonstration case. It will provide an example of an innovative approach to electrify the district heating sector through sector coupling with a focus on balancing the demands of DH with the changing prices in the electricity market. The case is based upon integration between the two existing energy systems: the Vystebø Wind Farm and the Hasle District Heating system.

3.3.1 Fundamental Technology: Principles, Maturity, and Applications in DH

The integration of wind energy into DH systems is a key enabler of the green transition. It allows surplus electricity from wind turbines to be converted into heat using electric boilers or heat pumps. This heat can then be stored or distributed through existing DH networks.

The principle is simple: when wind production is high and electricity prices are low, the system shifts to heat production. This not only reduces reliance on biomass and fossil fuels but also stabilizes the electricity grid by absorbing excess generation.

The technology is mature. Electric boilers are well-established, and large-scale heat pumps - especially CO₂-based air-to-water systems- are increasingly used in Denmark. These systems are compatible with smart grid technologies and can participate in electricity markets, offering flexibility and ancillary services.

On Bornholm, the concept is applied using a heat pump and electric boiler connected to the Vystebø wind park and the Hasle DH network. This creates a system capable of converting wind power to two different value streams: heat production when electricity prices are low or electricity sales to the grid when electricity prices are high.

3.3.2 Case Study Details: Location, Design, Capacity, and Stakeholders

This section outlines the technical and organizational setup of the Bornholm case.

Primarily owned by BEU, the district heating system on Bornholm consists of heat generation plants linked together by a series of pipes used to distribute heated water to private and commercial customers. The power used to generate the heated water supplied to customers is mostly produced by locally sourced straw or wood chips or diesel oil. The costs of these sources have remained relatively low; however, they will most likely increase in the future due to legislation, increased demand, or source scarcity.

Bornholm is transitioning from biomass to green energy for electricity and district heating production. In support, BEU is focusing on power production sources that consume green energy including district heating plants. In response to this, BEU has purchased green energy sources including solar and wind parks. This case study will focus on the Hasle District Heating Plant and will analyse the potential benefits of transitioning it from a biomass fuel source to a wind powered one provided by Vystebø Wind Park.

Hasle District Heating Area

Located on the western side of the island of Bornholm, Hasle District Heating area is supplied by the District Heating Plant (DHP) in Hasle and other plants located decentrally in Klemensker and Muleby. The plants

consist of biomass boilers, diesel oil boilers, and accumulation tanks and supplies district heating to 2.070 (2023) consumers in 8 towns. The total peak heat demand is 14 MW. The peak and reserve load capacity is 17,5 MW in total, and the peak load is covered by this capacity.

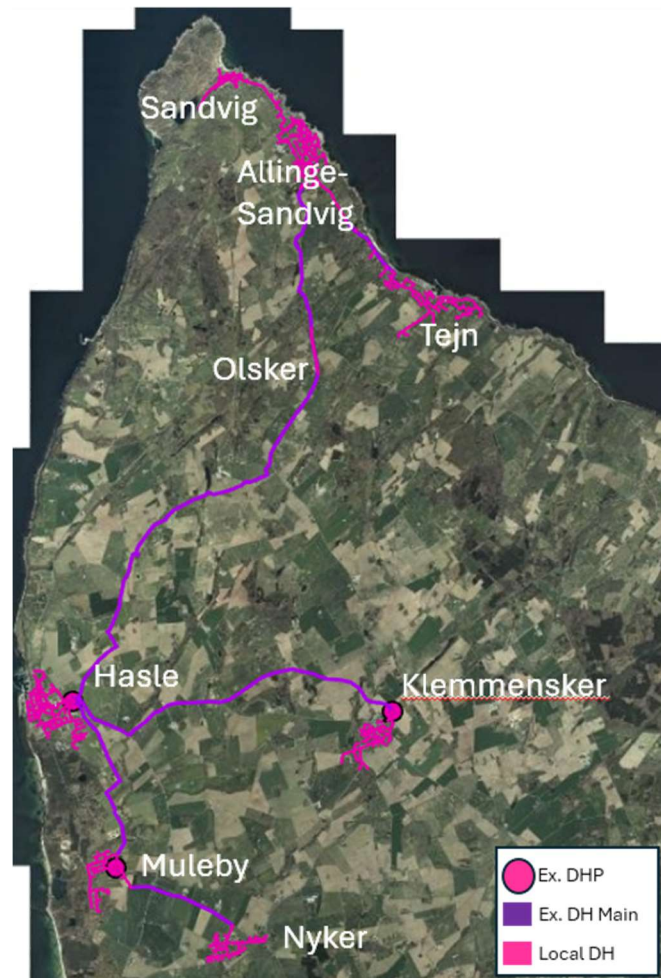


Figure 3.11: Map of the Hasle District Heating Area. 'Ex. DHP' is existing district heating plant, 'Ex. DH Main' is the existing heat transmission line and 'Local DH' is the local heat distribution network in the 8 cities in Hasle DH area.

In a reserve load situation, the plant in Hasle can only draw approx. 5 MW simultaneously due to the pipe dimensioning. It is therefore not possible to operate all plants in Hasle simultaneously and it is necessary to supply the area from both Hasle and Klemmenser, which is a major weakness in the case of island operation. In addition, Nordlandet (the cities in the north) in isolation has a lower security of supply, as the only supply is through the transmission line (Hasle – Allinge). Because of this a future sector coupling in Allinge is planned for 2027, where a 1 MW photovoltaic plant is connected to 2,2 MW electric boilers covering about 25% of the demand in Allinge, Sandvig and Tejn.

Approximately 55 GWh per year (2024) of district heating is produced through a combination of a straw/wood chip boiler and diesel oil. As the district heating plants age, their operations, maintenance, and repair costs will increase and the likelihood of issues occurring that could cause disruptions increases. Many of the existing biomass and oil boilers need replacement in 5 to 10 years. This is another reason why supplementing wind power or transitioning from biomass to wind power makes sense.

There are no expectations of new district heating areas or expansions in the Hasle DH Area, and the areas with the necessary catchment area have already established district heating. Customer growth will therefore be closely linked to population projections. The latest population projection at the municipal level showed that no growth is expected on Bornholm in the period 2023-2050. There is a potential 28% increase in customers for the Hasle heating area to account for potential existing customers who may decide to join the district heating system, but for this model we consider no increase in customers.

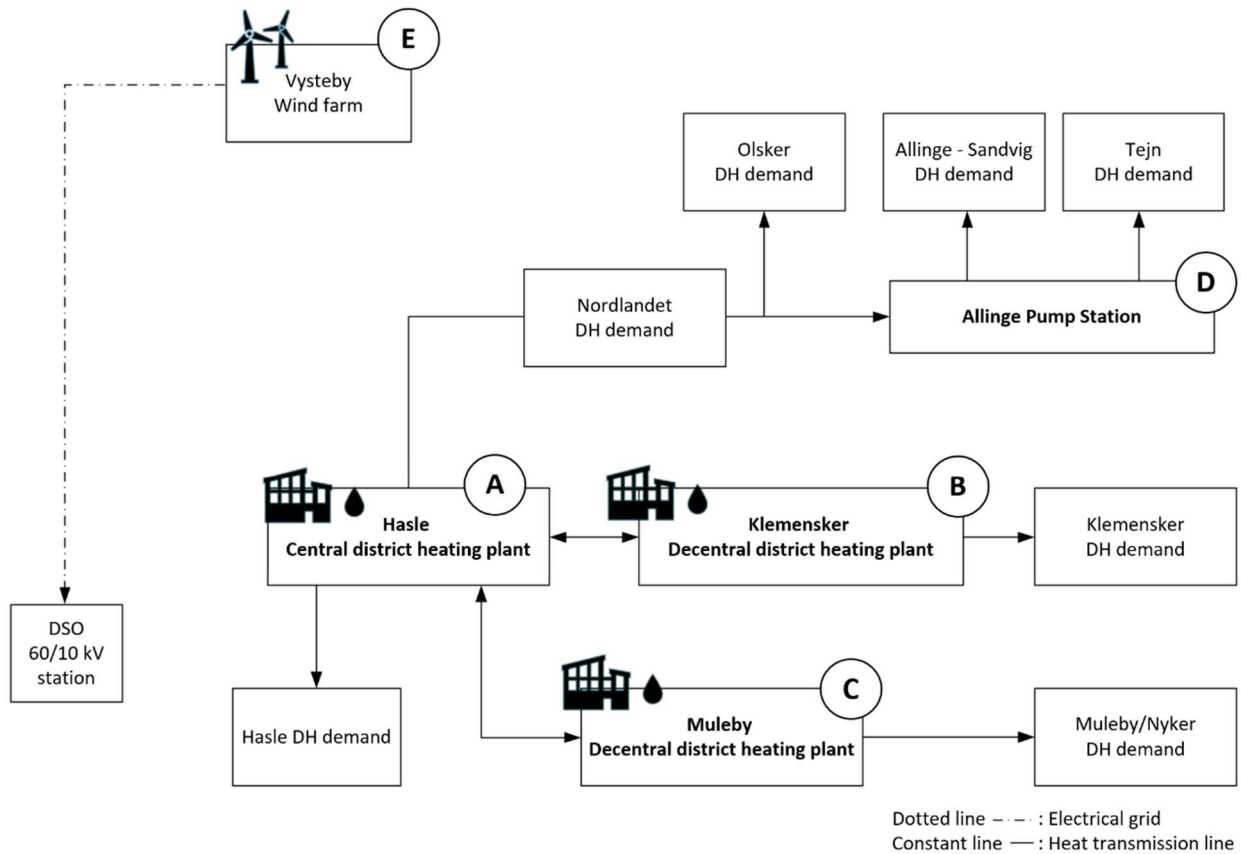


Figure 3.12: Diagram of the existing Hasle District Heating system and the local wind park, Vystebý.

Currently, heated water is created at the Hasle DH Plant and then distributed throughout the Hasle heating system. Additional supply may be created in Klemensker or Muleby if required by downstream consumers or the demand is higher than the amount Hasle DHP can supply. The Allinge pump station have a heat storage tank supplied from Hasle DHP and the heat is distributed to the cities Allinge – Sandvig and Tejn, see Figure 3.11 and Figure 3.12.

Vystebý Wind Park

Vystebý Wind Park consists of 3 Vestas V66-1.75 MW turbines constructed in 2006; each are directly connected to the electricity grid with a 2.100 kVA grid connection. They are located 500-600 m from the district heating transmission line, see figure 3. In 2023, the wind park produced approximately 15,5 GWh. A good income was obtained both from direct sale of electricity as well as from curtailment. The income from the curtailment indicates that excess electricity may be generated by the wind turbines that could be used to supply DH and/or stored in a battery and either sold or used for DH at a later time.



Figure 3.13: Existing DH and electricity system Hasle District Heating Plant (A) and Vysteby wind park (E).

Key Stakeholders

The stakeholders in this case study include:

- Bornholm Energy and Utility (BEU)
- Regional Municipality of Bornholm (RMB) - local municipalities
- TREFOR EI-net ØST (DSO) - local Distribution System Operator
- Energinet (TSO) - regulatory authorities
- The Danish Energy Agency (DEA) - regulatory authorities
- Consumers of district heating in the Hasle District Heating Area

Bornholm Energy and Utility (BEU)

BEU provides utility services to the island of Bornholm including district heating production and transmission, electricity production, drinking water, and wastewater. It consists of subsidiaries created to provide these resources. For simplicity, in this analysis, BEU will be viewed as one entity. In this scenario, BEU owns the district heating production and heat transmission lines and the energy production assets, like the electricity production from the wind turbines at Vysteby. The existing 60/10 kV station and grid are owned by the local Distribution System Operator, TREFOR EI-net Øst (DSO).

Regional Municipality of Bornholm (RMB)

- Environmental screening of a new plant
- The Project Executive Order sets the framework for municipal approval of collective heat supply projects under the Danish Heat Supply Act. Its purpose is to ensure that new district heating production units are planned and implemented in a way that is socio-economically sound, environmentally responsible, and aligned with national energy policy. Before construction begins, municipalities must review and approve project proposals based on a documented socio-economic analysis comparing alternatives, compliance with fossil fuel restrictions, and integration of renewable or electrified solutions. This process guarantees that new installations contribute to efficient, sustainable heat supply and are legally and technically robust within local heat planning.
- Building permit if needed – depends on final layout
 - May not be needed if technical equipment is < 30 m² and we are using existing footprint – eventually just upgrading the existing DHP

TREFOR EI-net ØST (DSO)

- As the Distribution System Operator, TREFOR EI-net ØST, owns, operates and manages the local distribution grid at Bornholm, and distributes electricity to the end-users. They operate the grid from low to high voltage up to 60 kV.
- TREFOR need to give permission to connect the new setup to the distribution grid

Energinet (TSO)

As the Transmission System Operator, Energinet is responsible for the transmission of electrical energy in Denmark. Energinet owns the high-voltage power lines (60 kV) supplying Bornholm via a transmission cable from southern Sweden. Their interest lies in ensuring that the grid remains stable and, to accomplish this, they work closely with the DSO. Current practices require that the DSO coordinate with the TSO and DEA for approval on behalf of BEU when a Direct Line Permit is required.

The Danish Energy Agency (DEA)

- As the regulatory authority, the Danish Energy Agency provides the permit for the direct line - Direct line, in this case, is the coupling of the wind farm and the electrical heat producing units at Hasle DHP

Consumers of district heating in Hasle DH area

- Want low cost and security of supply
- Likes green energy and sustainability
- Clean air (no biomass)

Vysteby Wind Park and Hasle DH area

Facts on Vysteby Wind Park and Hasle DH area:

- Location: Vysteby Wind Park and Hasle DH area, are placed northwest at Bornholm, Denmark
- Vysteby Wind Park: 3 × Vestas V66-1.75 MW turbines (total: 5,25 MW), producing 15,5 GWh (2023)
- District Heating System: Hasle DH area produced 55 GWh of heat in 2024, serving 8 towns and 2070 customers
- Hasle District Heating Plant, producing 81% (2024) of the heat for Hasle DH area
- Klemensker District Heating Plant, producing 19% (2024) of the heat for Hasle DH area
- Muleby District Heating Plant, producing 0,05% (2024) of the heat for Hasle DH area

Table 3.5: Overview of existing boilers and heat storage tanks at Hasle DH area and the units remaining useful life in years.

Location	Map	Component	Size	Remaining Useful Live as of 2024 (Years)
Hasle DHP	A	Wood chip boiler (base load)	13 MW	18
Hasle DHP	A	Flue gas condenser (base load)	2 MW	18
Hasle DHP	A	Heat Storage Tank	900 m ³ /53 MWh	2
Hasle DHP	A	Straw boiler (peak-/reserve load)	4 MW	9
Hasle DHP	A	Wood pellet boiler (peak-/reserve load)	2 MW	7
Hasle DHP	A	Oil boiler (peak-/reserve load)	3,5 MW	0
Klemensker DHP	B	Straw boiler (peak-/reserve load)	3,5 MW	5
Klemensker DHP	B	Oil boiler (peak-/reserve load)	3,5 MW	0
Klemensker DHP	B	Heat Storage Tank	800 m ³ /47 MWh	-1
Muleby DHP	C	Wood pellet boiler (peak-/reserve load)	1,0 MW	11
Muleby DHP	C	Heat Storage Tank	900 m ³ /53 MWh	6
Allinge Pump Station	D	Heat Storage Tank	2072 m ³ /113 MWh	12
Vysteby Wind Park	E	3 x Wind turbines	5,25 MW	7

Design - The integration of Wind Energy

Wind energy will be integrated through a direct electrical connection to heat-producing units (heat pump and electric boiler) strategically positioned along the 10 kV cable intersecting district heating (DH) pipelines. Switchgear and transformers will be installed to enable power transfer from the Vysteby wind park to the Hasle district heating plant (DHP). The configuration will also provide grid connection via the existing DSO 60/10 kV substation or directly at Hasle DHP. This setup allows electricity generated by the wind park to be utilized either within the DH system or exported to the grid, depending on market conditions.

The proposed solution includes installing a new heat pump and electric boiler at Hasle DHP and connecting the existing cable from the Vysteby wind farm to new switchgear located at Hasle DHP. Two additional cables will be required from Hasle DHP to the location for the exiting cable from the wind farm to the 60/10 kV station, see figure 4. Depending on the operating voltage of the heat-producing units, the 10 kV supply will either be used directly or stepped down via transformers at Hasle DHP.

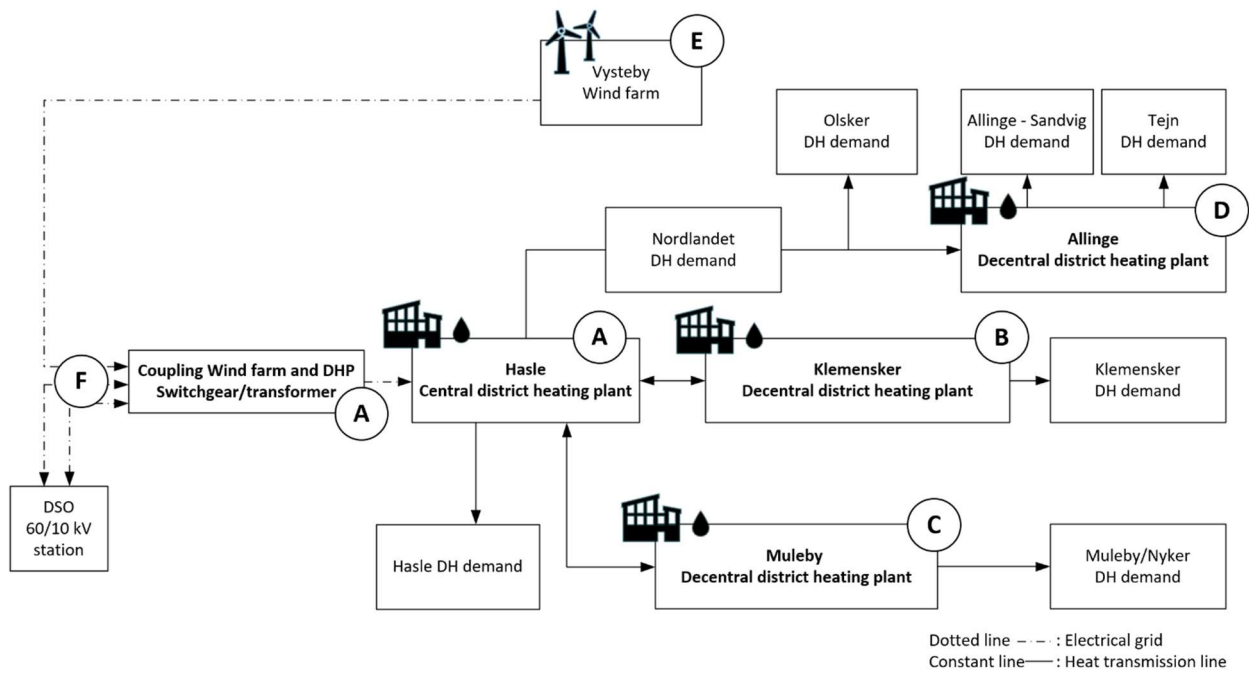


Figure 3.14: Diagram of proposed additions to the existing Hasle Heating area District Heating system.

Design choices

Based on an analysis of heat production in 2024 and the application of design principles for integrating heat pumps and electric boilers into district heating systems, several key assumptions have been established to form the foundation of the simulation scenarios.

In general, CO₂ air-to-water heat pumps have been selected. This choice is primarily driven by the location of the heat pumps, as there is no access to wastewater, seawater, or surplus heat in the area. CO₂ was chosen over ammonia due to safety considerations - being nontoxic and non-flammable - as well as its lower environmental impact.

In this case, three different scenarios will be analysed:

- **Scenario 1:** The existing configuration, where Hasle district heating plant (DHP) and the Vysteby wind farm are not interconnected.
- **Scenario 2:** Vysteby wind farm as the primary energy supplier to the Hasle district heating (DH) area, supplemented by biomass from the existing Hasle DHP.
- **Scenario 3:** Hasle DHP as the primary energy supplier to the Hasle DH area, supplemented by the Vysteby wind farm.

Scenario 1 is based on the existing configuration for the Hasle district heating area and the Vysteby wind farm, where no interconnection exists between them.

In Scenario 2, a heat pump has been selected to utilize a substantial share of the available wind energy. Due to its higher efficiency, the heat pump is activated significantly more often than the electric boilers, as its operational tipping point is more than three times higher. However, the heat pump has not been sized to match the full output of the wind farm, as this would result in excessive heat generation and require very large thermal storage capacity. Instead, the heat pump has been dimensioned to cover approximately 43%

of the peak heat demand, see Figure 3.16. The electric boiler in Scenario 2 is sized according to the peak load illustrated in Figure 3.15.

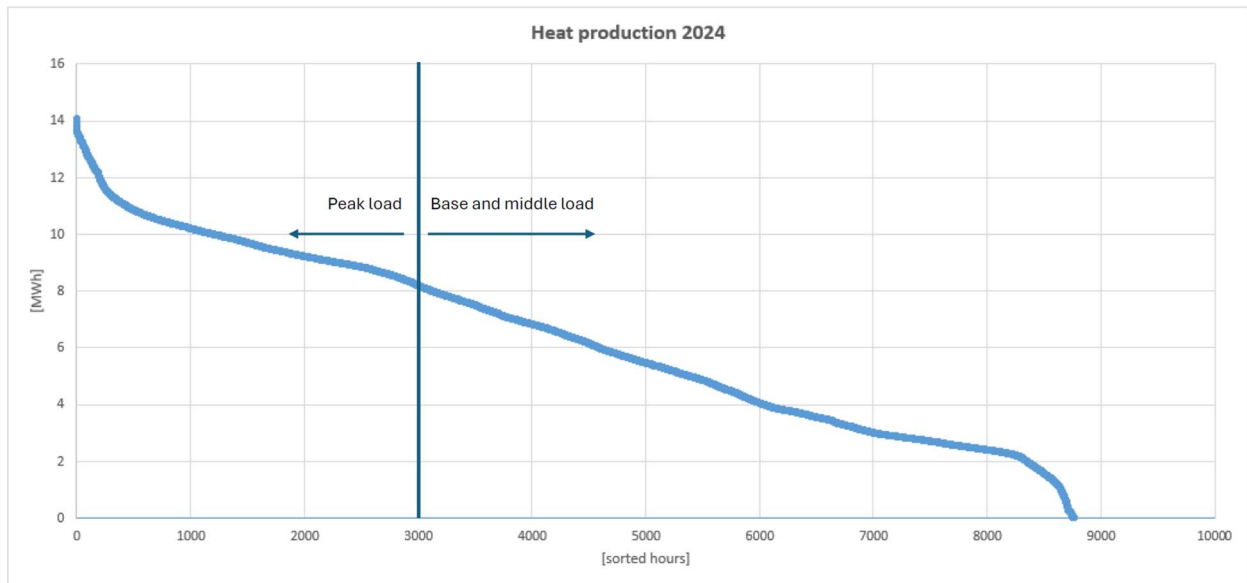


Figure 3.15: The heat production at Hasle DHP in 2024 sorted at hours. The 3000 Hours with highest production are denoted as peak load, the rest as base and middle load.

In Scenario 3, the heat pump is sized to match the base load heat production, as illustrated in Figure 3.16. Since heat pumps represent a significant investment, it is essential to avoid oversizing. The electric boiler in Scenario 3 is designed to utilize the remaining available wind energy. The wind farm produces approximately 5 MW of usable energy for electric heat-generating units; with the heat pump consuming about 1 MW_{el}, the electric boiler is therefore dimensioned at 4 MW_{el} in this case.

In both Scenarios 2 and 3, an additional heat storage tank of 2,747 m³ / 150 MWh has been included. For Scenario 2, this corresponds to 460 m³ per MW of combined heat pump and electric boiler capacity, assuming the existing storage tanks at Hasle and Klemensker are replaced with this unit. For Scenario 3, the ratio is 788 m³ per MW.

Furthermore, it is recommended to install a new wood-chip boiler to replace the existing units that will reach the end of their service life within the next few years.

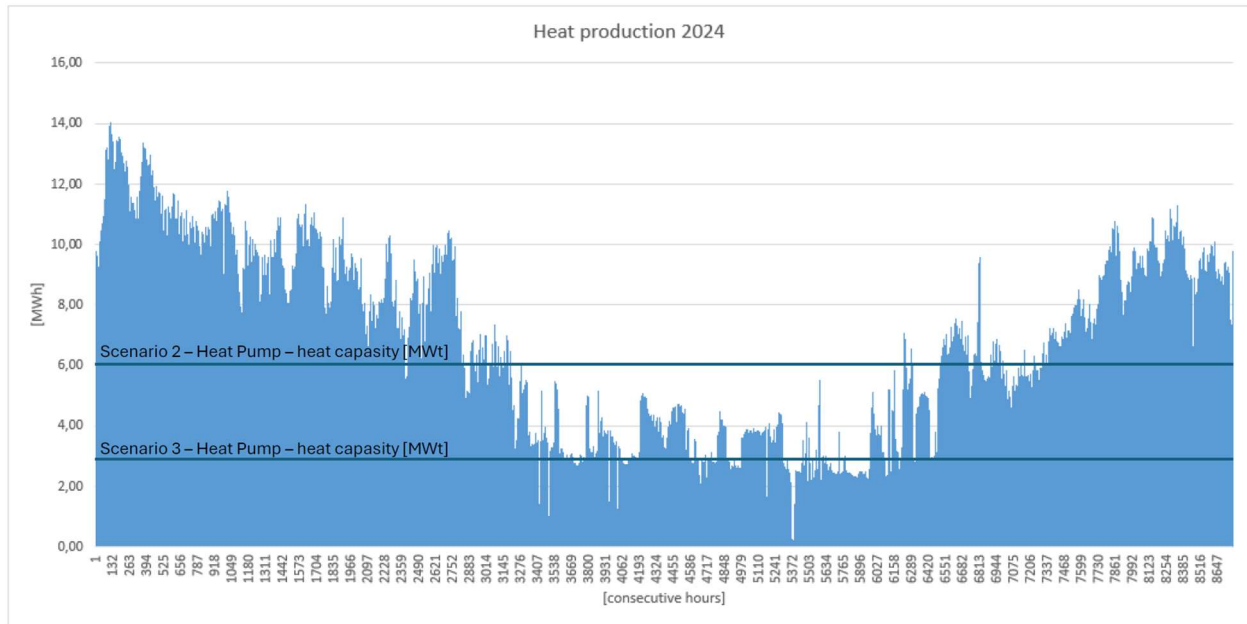


Figure 3.16: The heat production at Hasle DHP in 2024

Table 3.6 provides an overview of the components to be retained, removed, and newly introduced for the integration of the existing Vystebý wind park with the Hasle district heating plant (DHP) across different scenarios.

Table 3.6: Existing and new components at Hasle DHP and Vystebý Wind Park, see also figure

Location	Map	Component	Size	Action
Hasle DHP	A	Wood chip boiler	13 MW	Keep
Hasle DHP	A	Flue gas condenser	2 MW	Keep
Hasle DHP	A	Heat Storage Tank	900 m ³ /53 MWh	Keep
Hasle DHP	A	Straw boiler	4 MW	Remove
Hasle DHP	A	Wood pellet boiler	2 MW	Remove
Hasle DHP	A	Oil boiler	3,5 MW	Remove
Hasle DHP	A	Heat Storage Tank		Proposed
		Scenario 1:	-	
		Scenario 2:	2547 m ³ /150 MWh	
		Scenario 3:	2547 m ³ /150 MWh	
Hasle DHP	A	CO ₂ Heat Pump (AW)		Proposed
		Scenario 1:	-	
		Scenario 2:	SCOP 3,0 – 6 MW/10 kV	
		Scenario 3:	SCOP 3,0 – 3 MW/690 V	
Hasle DHP	A	Electric Boiler		Proposed

		Scenario 1:	-	
		Scenario 2:	6 MW/10 kV	
		Scenario 3:	4 MW/690 kV	
Hasle DHP	A	Wood chip boiler	6 MW	Proposed
Hasle DHP	A	Switchgear	10 kV	Proposed
Hasle DHP	A	Transformer		
		Scenario 1:	-	Proposed
		Scenario 2:	-	
		Scenario 3:	10/0,69 kV	
Hasle DHP Switchgear/transformer to Heat pump/electric boiler	A	Cable		
		Scenario 1:	-	Proposed
		Scenario 2:	Medium voltage/10 kV	
		Scenario 3:	Low voltage/690 V	
Vysteby Wind Park	E	3 x Wind turbines	5,25 MW/10 kV	Keep
Vysteby Wind Park to DSO 60/10 kV station	E	Cable	Medium voltage/10 kV	Keep
From existing connecting cable to Wind Park to Hasle DHP Switchgear	F	Cable	Medium voltage/10 kV	Proposed
From Hasle DHP Switchgear to existing DSO 60/10 kV station	F	Cable	Medium voltage/10 kV	Proposed
Hasle DHP	A	Wood chip boiler	13 MW	Keep

3.3.3 Integration Plan: Technical Steps, Infrastructure Requirements, Timeline

This section describes how the integration is technically and logistically achieved. Especially the last technical steps lie far out in future.

Future technical Steps:

- Evaluation of transformer and cable capacities – possibly new transformer station
- Calculating costs associated with taxes and handling biomass at the DH plant, for heat production using biomass and future O & M and replacement costs
- Calculating earnings from NOT running the turbines
- Design of control systems using PLC (Programmable Logic Controller) and RTU (Remote Terminal Unit) for real-time optimization

- Calculating savings of biomass in tons for the next 25 years
- Seeing biomass as a CO₂ emitting source - Calculating CO₂-savings for not using biomass for heat production
- Additional cost savings if batteries are used to store wind turbine power when electricity costs are high and wind turbine power is unavailable
- Design and cost of system (wind turbines, land, battery, electric boiler, heat pump, etc.)
- Costs associated with future O & M, repairs, and replacement of Hasle District Heating Plant
- Compliance with ESG requirements and targets should be verified
- Wind availability to determine amount of electricity available if wind turbines are not turned off, thereby avoiding curtailment (in DKK) - assuming that it could be sold or used for DH

Technical Steps analysed in this report:

- Mapping of existing infrastructure (wind park, DH network, electrical grid, inclusive effect, and capacities)
- Selection of future heat-producing technologies (CO₂ heat pump and electric boilers)
- Dimensioning heat-producing units from required needs in the local DH system
- Dimensioning of heat storage tank
- Calculating costs associated with heat production using biomass at Hasle DHP
- Calculating costs and income streams associated with wind turbines - DH production and sales to the grid
- Simulation of scenarios (hourly simulations)

Infrastructure Requirements:

- Placement of units near intersections of 10 kV cable and DH pipelines
 - At existing DH plant or a new plant closer to DH pipelines
- Installation of thermal storage (e.g. existing accumulation tank)
 - Replace existing thermal storage and build new and bigger
- Smart grid and control systems
- Compliance with Energinet and Green Power Denmark (GPD) regulations

Model Values and Assumptions

The impacts of leveraging wind turbine power for DH were analysed using a simulation model created for this case study.

- Allowed for the right-sizing of the components
- Allowed for the use of either wind turbine power or biomass to understand how often biomass will be required due to no wind availability

Input Values to the model

- Wind turbine production and sales (in MWh and DKK)
- Wind profile - built on place and size of turbine and estimated wind availability
- Local historical DH production (2024) in MWh - taking into account the future heat production of the sector coupling in Allinge
- Amount of biomass used for DH and cost to purchase/store
- Electric boiler, size in MW and SCOP-value = 1 (Seasonal Coefficient of Performance) - lower tipping point because of the nearly 100% efficiency between used electricity in MW_{el} (MW electric) and heat production in MW_{th} (MW thermal).

- CO2 AW Heat pump, size in MW_{el} and SCOP-value = 3 (Seasonal Coefficient of Performance), producing base load, estimated from local historical DH production (2024)
 - A CO2 AW heat pump will have an effectiveness between 290% to 410% varying over the year depending on the ambient temperature.
 - In the simulation model, a conservative average SCOP-value is chosen.
 - The heat pump has a high tipping point because of the 300% efficiency.
- Existing heat storage tanks in total, sized in MWh
- New heat storage tank, sized in MWh
- Tariffs on consuming and production of electricity from/to the grid, DKK/MWh
 - It has been decided to use the existing tariff group of the wind farm (B-high) – DSO owning the cable from wind park to DSO 60/10kV station
- Tipping point for when to sell energy to grid instead of using the energy for heat production with electric boiler, DKK/MWh
- Tipping point for when to sell energy to grid instead of using the energy for heat production with heat pump, DKK/MWh

Table 3.7: Input sizes and estimated amount of wind energy production per year.

Input	Unit	Amount/Size
Wind farm, estimated production	GWh/yr	15,0
Heat production, max load	MW	14,0
Heat production, base and middle load	MW	8,1
Heat production, peak load	MW	5,9
New heat pump, SCOP 3,0	MW_{th}/MW_{el}	
Scenario 1		-
Scenario 2		6,0/2,0
Scenario 3		3,0/1,0
New electric boiler, SCOP 1,0	MW_{th}/MW_{el}	
Scenario 1		-
Scenario 2		6,0/6,0
Scenario 3		4,0/4,0
Existing Heat Storage Tank, total	MWh	266

Assumptions

- Wind turbine power is the primary electricity source for DH production.
- Wind profile: Future wind availability will follow historical trends.
- DH and electrical grid are the consumers of the produced wind energy, where DH has first priority.
- Electricity and DH sales trends are consistent.

- The historical total heat production is from the whole Hasle DH area.
- The heat production used in the simulation model is only what is produced at Hasle DHP (81% of the total production in the area), because it is only a possibility to connect the wind farm to this DHP.
- Population in Hasle Heating Area is static (estimated maximum growth of customers 28%) – this possible increase is not included in the simulation.
- Excess electricity from wind turbines NOT used by DH will be sold to the grid.
- The cost for biomass is based on the historical price for 2024, with an additional 15% added to cover taxes and handling.
- Using historical biomass costs (2024) with inflation of 2% per year.
- The model does prioritize satisfying the district heating demand over selling to the electrical grid.
- Electricity will be sold to the highest bidder (electricity grid or district heating) based on a static minimum (tipping point for either heat pump or electric boiler).
- Only use wind energy for heat production if the cost is below the price of using biomass.
- Because of the use of only 0,01% oil in the distribution of fuel in 2024, see table 6, and that fact that the two oil boilers must be removed because of their remaining year, see table 1, in the simulation only biomass would be used.

Timeline: While no fixed timeline is defined, the project aligns with BEOF's 2032 strategy to reduce biomass use and increase electrification. The purpose of the project also aligns well with the municipal energy plan for 2040.

Before proceeding, more analysis is required, including detailed engineering and a more robust economic model. Requirements for including a solar cell park and a battery will also be investigated.

3.3.4 Expectations: Predicted Energy Output, Cost Savings, Scalability

This section quantifies the expected performance and economic benefits.

The simulation model has tested different scenarios:

- Scenario 1: The existing setup, where Hasle DHP and the Vysteby wind farm are not connected
- Scenario 2: Vysteby wind farm as the primary provider of energy to Hasle DH area with supplement from the existing Hasle DHP by biomass
- Scenario 3: Hasle DHP as the primary provider of energy to Hasle DH area with supplement from Vysteby wind farm

Scenario 1 - Simulated Output:

Scenario 1, is using the existing setup, where Hasle DHP and Vysteby wind farm are not connected, see Figure 3.12: Diagram of the existing Hasle District Heating system and the local wind park, Vysteby..

The income, cost and heat production in this scenario are as follows:

- a. Sale of wind energy from 5,25 MW wind farm, estimated production 15 GWh/yr.
- b. Cost of fuel (biomass and oil) to cover the existing heating demand in Hasle DH area.

Table 3.8: The estimated heat production in GWh using the existing setup at Hasle DH area, producing heat by biomass- and oil boiler.

The estimated heat production in [GWh]	2025	2030	2040	2050
Total heat demand/production*	55,48	53,58	52,26	51,16
Heat production, biomass	55,48	53,58	52,26	51,16

* The estimated heat demand/production is reduced over time because of the future sector coupling in Allinge. In ultimo 2027 a 1 MW photovoltaic plant will supply a 2,2 MW electric boiler, both connected to the grid, selling the PV energy when electricity prices are high and producing heat when electricity prices are low.

In this scenario, it is expected that the use of biomass and oil would correspond to the use of fuel in 2024, the distribution in ton for biomass and m³ for oil, can be seen in Table 3.9.

Table 3.9: Biomass and oil used for heat production in Hasle DH area in 2024.

Biomass and oil used for heat production	Wood chips [ton]	Straw [ton]	Wood pellets [ton]	Oil [m ³]
Hasle DHP	10.852	3052	14	-
Klemensker DHP	-	2820	-	0,4
Muleby	-	-	7	-
Total	10.852	5.872	21	0,4

Table 3.10: Distribution of fuel in MWh and % for Hasle DH area I 2024

Distribution of fuel in [MWh] and [%]	2025	2030	2040	2050
Distribution of fuel MWh]	31.314	23.651	102,7	3,98
Distribution of fuel [%]	56,9	42,9	0,19	0,01

The estimated income for wind energy and fuel costs for this scenario is displayed in Table 3.11.

Table 3.11: Estimated income(+) in M€ (incl. 2% inflation) from the wind farm selling all the energy to the electrical grid if not coupling to DH and estimated cost(-) for fuels if not coupling the wind farm to the DH – estimated from fuels cost in 2024

Estimated income in [M€]	2025	2030	2040	2050
Income from selling electricity from wind farm on the Day-Ahead market wind farm	1,010	0,607	0,493	0,484
Costs to fuel, biomass	2,188	2,416	2,945	3,589
Total expenses	-1,178	-1,809	-2,452	-3,106

Scenario 2 - Simulated Output:

In Scenario 2 Vysteby wind farm is the primary supplier of energy to Hasle DH area with supplement from the existing Hasle DHP by biomass, se figure 4.

The components in this scenario would be:

- Vysteby Wind farm - Wind energy production 15 GWh/year.
- Prioritized as follows, when the energy price is under the tipping point for selling the energy to the grid:
 - Wind energy driven heat pump, if there is a heat demand and/or available space in the heat storage tank.
 - Wind energy driven electric boiler, if there is a heat demand and/or available space in the heat storage tank.
 - Wind energy is sold to the grid.
- 6 MW CO₂ heat pump (SCOP 3,0).
 - A 6 MW heat pump can cover 43% of the peak heat production of 14 MW.
- 6MW electric boiler (SCOP 1,0).
- 150 MWh heat storage tank to store the heat produced then the wind farm produces energy and/or the electricity prices are low.

The simulation model has estimated a heat production which distributes as shown in Figure 3.17: Estimated heat production from wind energy using a 6 MW heat pump and a 6 MW electric boiler. The rest of the heat demand is reached using electricity from the grid and biomass. As the figure illustrates, from 2025 through 2050,

wind energy heat pump and wind energy electrical boiler produces 75 to 84% of the heat needed per year, only 8 to 15% of the heat would be produced from biomass. The heat pump would use energy from the grid to produce 6 to 12% of the heat.

At Table 3.12 the division of heat production shown in GWh estimated the next 25 years, the varies over the years are because of the change in the electricity prices.

Table 3.13 displays the estimated income from the wind farm and the cost to biomass for Scenario 2.

Table 3.12: Estimated heat production in GWh from wind energy using 6 MW heat pump and 6 MW electric boiler. The rest of the heat demand is reached using biomass.

Estimated heat production in [GWh]	2025	2030	2040	2050
Total heat demand/production	55,48	53,58	52,26	51,16
Heat production, heat pump, wind energy	39,55	38,17	37,63	37,03
Heat production, heat pump, grid	5,23	6,69	4,58	2,83
Heat production, electric boiler, wind energy	2,32	4,09	5,69	6,32
Heat production, electric boiler, grid	0	0	0	0
Heat production, biomass	8,39	4,64	4,36	4,98



Figure 3.17: Estimated heat production from wind energy using a 6 MW heat pump and a 6 MW electric boiler. The rest of the heat demand is reached using electricity from the grid and biomass

Table 3.13: Estimated income (+) and cost (-) in M€ if coupling the wind farm to Hasle DHP using 6 MW heat pump and 6 MW electric boiler

Estimated income and cost in [M€]	2025	2030	2040	2050
Income from selling surplus electricity from wind farm on the Day-Ahead market wind farm	0,437	0,194	0,076	0,120
Costs to fuel, biomass	0,328	0,217	0,236	0,359
Total income/expenses	0,109	-0,023	-0,160	-0,239

Scenario 3 – Simulated Output:

In Scenario 3 Hasle DHP is the primary supplier of energy by biomass to Hasle DH area with supplement from Vysteby wind farm, se figure 4.

The components in this scenario would be:

1. Vysteby Wind farm - Wind energy production 15 GWh/year.
 - a. Prioritized as follows, when the energy price is under the tipping point for selling the energy to the grid:
 - i. Wind energy driven heat pump, if there is a heat demand and/or available space in the heat storage tank.
 - ii. Wind energy driven electric boiler, if there is a heat demand and/or available space in the heat storage tank.
 - iii. Wind energy is sold to the grid.
2. 3 MW CO₂ heat pump (SCOP 3,0).
 - a. A 3 MW heat pump can cover 21% of the peak heat production of 14 MW.
3. 4 MW electric boiler (SCOP 1,0).
4. 150 MWh heat storage tank to store the heat produced then the wind farm produces energy and/or the electricity prices are low.

The simulation model has estimated a heat production which distributes as shown at Figure 3.18. As the figure illustrates from 2025 through 2050, 50 to 61% of the heat production is produced by biomass. Wind energy produces 37 to 48% of the heat needed and the heat pump would use energy from the grid to produce 2 to 4% of the heat.

At Table 3.14 the division of heat production shown in GWh estimated the next 25 years, the varies over the years are because of the change in the electricity prices.

Table 3.15 displays the estimated income from the wind farm and the cost to biomass for scenario 3.

Table 3.14: Estimated heat production in GWh from wind energy using 3 MW heat pump and 4 MW electric boiler. The rest of the heat demand is reached using biomass

Estimated heat production in [GWh]	2025	2030	2040	2050
Total heat demand/production	55,48	53,58	52,26	51,16
Heat production, heat pump, wind energy	16,65	16,42	16,24	15,71
Heat production, heat pump, grid	1,33	2,19	1,54	0,95
Heat production, electric boiler, wind energy	3,70	7,17	8,41	8,78
Heat production, electric boiler, grid	0	0	0	0
Heat production, biomass	33,81	27,80	26,07	25,72



Figure 3.18: Estimated heat production from wind energy using 3 MW heat pump and 4 MW electric boiler. The rest of the heat demand is reached using electricity from the grid and biomass.

Table 3.15: Estimated income(+) and cost(-) in M€ if coupling the wind farm to Hasle DHP using 3 MW heat pump and 4 MW electric boiler.

Estimated income and cost in [M€]	2025	2030	2040	2050
Income from selling surplus electricity from wind farm on the Day-Ahead market wind farm	0,504	0,194	0,129	0,165
Costs to fuel, biomass	1,335	1,256	1,472	1,795
Total expenses	-0,831	-1,062	-1,343	-1,630

Cost Savings:

In the tables below, Table 3.16 and Table 3.17, the income or cost for each scenario are displayed for the specific years 2025, 2030, 2040 and 2050, and the savings and cost for each scenario for the next 25 years.

Table 3.16: Overview over the three simulated scenarios showing income(+) and cost(-) in M€ for the specific years, 2025, 2030, 2040 and 2050.

Estimated Income or cost savings (M€)	2025	2030	2040	2050
Scenario 1 Total cost, if <u>not</u> connecting wind farm to DH	-1,178	-1,809	-2,452	-3,106
Scenario 2 Total income/cost, connecting wind farm to DH (6 MW Heat Pump and 6 MW Electric Boiler)	0,109	-0,023	-0,160	-0,239
Scenario 3 Total cost, connecting wind farm to DH (3 MW Heat Pump and 4 MW Electric Boiler)	-0,831	-1,062	-1,343	-1,630

Table 3.17: Overview over the estimated income (+) and savings (+) for each scenario in the next 25 years and the total cost (-) in M€ for heat production. The three different scenarios have an average of 100, 10,46 and 53,24% heat production from biomass.

Estimated income, cost, and savings in the next 25 years (M€)	Scenario 1 Average of 100% Biomass	Scenario 2 Average of 10,46% Biomass	Scenario 3 Average of 53,24% Biomass
Cost to biomass	-73,87	-7,73	-39,33
Savings in cost to biomass	0	66,14	34,54
Yearly average saving of biomass	0	2,65	1,38
Income from selling surplus electricity from wind farm, on the Day-Ahead market	15,17	4,19	5,17
Total cost	-58,70	-3,54	-34,16

Discussion

Scenario 1 - Hasle DHP and Vystebý wind farm not connected – Existing

In this scenario, the expected expenses over the next 25 years are estimated at €58.7 million, as shown in Table 3.17. Heat production will be supplied entirely from biomass, the existing procedure of using biomass for heat production will continue, while the wind farm will keep producing electricity for the day-ahead

market. There will be no advantage in utilizing wind energy for heat production when electricity prices are low or when the turbines are curtailed. The existing oil boilers require replacement, and the straw boilers will also need replacement within a few years, as shown in Table 3.5. Therefore, a decision must be made whether to replace them with electric heating units instead of new biomass boilers. Maintaining the current setup is clearly the most expensive option.

Scenario 2 - Vysteby as primary with DHP as supplement

In Scenario 2, the expected cost over the next 25 years is estimated at €3.54 million, as shown in Table 3.17. The oil and straw boilers that require replacement in the coming years would be substituted with a 6 MW CO₂ air-to-water heat pump capable of providing base and mid-load throughout the year, and a 6 MW electric boiler for peak load when required. For peak and reserve capacity, the existing wood chip boiler and flue gas condenser will remain in operation. A thermal storage unit of 150 MWh will supplement the existing 266 MWh, of which 100 MWh will soon reach the end of its service life.

Revenue from the wind farm will decrease due to the utilization of wind energy for district heating; electricity will be sold on the day-ahead market when prices are high, while electric heat production will occur when electricity prices are low. This scenario offers the most favourable business case, primarily due to the high efficiency of the heat pump and its integration with the electric boiler, which operates when the heat pump reaches its production limit and surplus wind energy is available. Furthermore, the heat pump can also produce heat using electricity from the grid when wind energy is unavailable but electricity prices remain low.

Only 10.5% of the heat production would come from biomass in this scenario. The main disadvantage is the high cost of investment, installation, and grid connection for the heat pump, with an estimated price of €1,4 million per MW and for electric boilers €0,14 million per MW¹.

The simulation model clearly indicates that this scenario delivers the greatest savings in both costs and biomass over the short and long term; however, investment costs have not been included in this report.

Scenario 3 - Hasle DHP as primary with Vysteby as supplement

In Scenario 3, the expected cost over the next 25 years is estimated at €34.16 million, as shown in Table 13. A 3 MW_t CO₂ air-to-water heat pump is selected to supply the base load heat demand. This heat pump consumes only about one-fifth of the wind energy (approximately 1 MW_e) when the wind farm operates at maximum output. Instead, the 4 MW electric boiler utilizes the wind energy; however, with an efficiency around 99%, it delivers no more than 1.33 MW_e of heat, compared to what the heat pump would produce.

The electric boiler is activated less frequently than the heat pump because the heat pump has a higher tipping point relative to electricity prices due to its superior efficiency. Therefore, even if the electric boiler were larger in this scenario, it would not be activated more often.

As a result, 53.2% of heat production in this scenario is generated from biomass, leading to a significant biomass cost, while revenue from wind energy does not increase substantially since the electricity is sold relatively cheaply on the day-ahead market.

Conclusion

The simulation results clearly demonstrate that integrating wind energy with district heating provides significant advantages - both economically, in reducing biomass consumption, and from an overall environmental perspective. Another benefit of using wind and solar energy directly in district heating is that

¹ Technology Data - Energy Plants for Electricity and District heating generation, number 11, Danish Energy Agency and Energinet

it prevents overloading of the power grid during periods of high production from both sources. This relief on an already stressed distribution network enables the deployment of additional renewable energy capacity in connection with heating plants. With thermal storage tanks, surplus renewable energy can be utilized for district heating when the grid does not require it, and sold on the day-ahead market when demand arises. Furthermore, electric heat-producing units can assist in grid regulation and generate additional revenue, helping to keep heating prices low for customers.

Scalability:

- The model is modular and adaptable
- Suitable for replication in other South Baltic regions with wind and DH infrastructure
- Can be scaled up or down depending on local demand and grid capacity

3.3.5 Challenges: Risks and Mitigation

This section identifies potential barriers and how they can be addressed.

Risks:

- Wind variability and mismatch with heat demand
- Limited thermal storage capacity
- Regulatory uncertainty around co-located systems
- High connection fees in some geographical zones
- Greater increase or decrease in demand than expected

Mitigation:

- Use of thermal storage to buffer production
- Smart control systems to optimize operation based on electricity prices and demand
- Conservative design assumptions (e.g., SCOP = 3.0) to ensure robustness
- Flexible placement of units along the 10 kV line to reduce infrastructure costs

3.3.6 Impact Assessment: CO₂ Reduction, Job Creation, Social Acceptance

This section evaluates the broader societal and environmental benefits.

CO₂ Reduction:

- Significant reduction by replacing biomass and fossil fuels with wind-powered heat
- Supports Denmark's 2050 fossil-free target
- Can estimate the amount of CO₂ saved by converting the amount of wind power used to biomass and calculating

Job Creation:

- Local employment in installation, maintenance, and system operation
- Potential for new roles in energy market participation and digital control systems

Social Acceptance:

- High, due to Bornholm's existing wind infrastructure and public support for green energy
- No new wind turbines required, reducing visual and environmental impact

3.3.7 Policy and Regulatory Considerations

This section outlines the legal and policy framework relevant to the project.

EU and National Alignment:

- Supports EU Renewable Energy Directive and Denmark's climate goals
- Encourages sector coupling and electrification of heat

Incentives and Permitting:

- Eligible for system services revenue (e.g., frequency regulation)
- Direct line connections under new "Direkte linje" legislation (2023)
- Must comply with GPD and Energinet technical requirements

Barriers:

- Ambiguity in classification of "samplacerede anlæg" (co-located systems)
- High connection fees depending on geographical zone classification (e.g., DKK 1.7 million/MVA in red zones)

Policy Gaps and Advocacy:

- Need for clearer frameworks for flexible, co-located energy systems
- Advocacy for reduced tariffs and simplified permitting for renewable heat project

3.4 *LEI: Transfer from natural gas to biomass in Kaunas*

Since Kaunas City (as all other Lithuanian municipalities) till year 2010 was operating mainly on natural gas and heavy fuel oil as reserve fuel (biomass made just 4%), the decision to support the transition towards renewable solutions, which in the case of Lithuania, was biomass, led to a huge reorganisation of Kaunas City district heating sector towards the use of biomass.

Some common types of biomasses for heating in Lithuania's towns are:

- Wood can be used in various forms, such as logs, chips, pellets, or briquettes, however, large installations (≥ 5 MW) usually burn wood chips from cutting residues.
- Agricultural residues are the by-products of crop production, such as straw, stalks, husks, shells, or cobs. They are used mainly in rural areas, and is mainly straw in Lithuanian district heating.
- Biogas is a mixture of gases, mainly methane and carbon dioxide, produced by the anaerobic digestion of organic matter, such as animal manure, sewage sludge, food waste, or crop residues. It can also generate heat and electricity through CHP systems or fuel cells.
- Minor amounts of peat can be also used in the fuel mix.

Biomass boilers operating in district heating can be divided by the type of biomass into:

- Solid biomass (wood chips, energy plants, renewable share of municipal solid waste (MSW)) – most appropriate to use in boiler-houses and CHP plants of cities, large towns, as was the case in Kaunas City;
- Compressed solid biomass (wood, agricultural waste pellets) – appropriate for smaller towns, settlements, where automatic container-type boilers can be used;
- Biogas – can be used in locations where biogas is available (from farming, landfills, food industry) and/or gas pipelines exist, and biogas can be cleaned and injected into the pipelines;

3.4.1 **Fundamental Technologies: Principles, maturity, and applications in DH**

Technological solutions, which are the most appropriate for implementation in district heating systems, and which are all of the highest maturity or readiness levels, are TRL8 (System complete and qualified) and TRL9 (Actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies; or space). The most appropriate technologies for biomass energy in district heating in Kaunas City are as follows:

- Grate firing is a type of industrial combustion system used for solid fuels. It is now used mainly for burning waste and woody biomass.
- Fluidised bed combustion (FBC) is a combustion technology used to burn solid fuels. Fluidisation is a way to mix fuel and air to get combustion. A fluidised bed is defined as a bed of solid particles that behaves like a fluid. This technology better works with variable fuel mix.
- Biogas boilers/CHP plans. Biogas can be used locally for heating or combined heat and power production. Alternatively, energy producers can upgrade biogas to biomethane.

3.4.2 **Case Study Details**

To reduce the use of fossil fuels (natural gas) in heat production, in 2012, Kauno Energija began investing in the construction of biofuel-fired heating plants. With the support of the European Union Structural Funds and the Lithuanian Environmental Investment Fund, Kauno Energija has invested more than €5.38 million

in the construction of biofuel boiler houses over the past few years. This has allowed the share of heat produced from renewable energy sources to increase from 11% to 90%.

3.4.3 Integration Plan: Technical steps, infrastructure requirements, timeline


The first Kaunas City Renewable Energy Development Action Plan was adopted by the Kaunas City Council in 2010, and in 2016, it was revised. Thus, the situation in 2010 should be considered as the starting year of transition process. Any technological solution needs infrastructure, technical requirements based on the requirements of specific technology and national legislation.




The implementation steps should mainly include:




1. The process begins with the assessment of data on biomass resources. Currently, biomass is obtained mainly from Baltpool International Biomass Exchange.
2. Selection of the site should be implemented concerning access to necessary infrastructure, available consumers and significant area availability for fuel storage and auxiliary installations, such as fuel weighing systems, etc.
3. Designing heat and/or power generation systems that are compatible with existing heat pipelines and electrical grids, as well as water supply systems. Sewerage management and ash removal systems are also necessary.
4. Energy and fuel efficiency solutions, such as condensing economisers, heat storage, etc., should be evaluated. Implementing safety standards and ensuring regulatory compliance.
5. Integrating data-driven solutions to monitor performance and predict equipment failures.
6. All legally required permissions should be received before the start of construction.
7. The incorporation of data analytics into biomass grid integration cannot be overstated. In an industry that relies heavily on precision and efficiency, predictive modelling and data analysis techniques provide a competitive edge.

The timeline of the transition process can be seen in Table 3.1 and Table 3.19.

Table 3.18: Replacement with biomass boilers in boiler-houses of Kaunas DH company.




No.	Boiler-house information	Capacity	Investment	Year
1	Developer UAB ENG – transferred to Kaunas DH company Kauno energija, biomass boiler-house in Garliava (suburb of Kaunas City), Constructing company Axis Industries 	Boiler capacity – 5.2 MW, Condensing flue gas economiser – 1.3 MW, Total 6.5 MW	1,74 mill €	2012

2	<p>Developer – Kaunas DH company Kauno energija – “Šilkas” boiler-house.</p> <p>Replacement was implemented in two stages</p> 	<p>Water heating boiler HHB9000 – 10 MW,</p> <p>Condensing flue gas economiser – 4 MW,</p> <p>Water heating boiler AK800P10T130 – 8 MW,</p> <p>Total 22 MW</p>		<p>2013</p> <p>Second stage: 2015</p>
3	<p>Developer - Kaunas DH company Kauno energija – Ežerėlis boiler-house.</p> <p>Boiler for peat, sawdust and straw. The boiler was designed on order and constructed by a consortium of UAB „Energijos taupymo centras“, UAB „Enerstena“ and AB „Axis Industries“.</p> 	<p>Boiler – 3.5 MW,</p> <p>Condensing flue gas economiser – 1.5 MW,</p> <p>Total 5 MW</p>	<p>Partial funding of nearly 0.52 million € from the Lithuanian Environment Investment Fund (LAAIF). Total project value 1.32 million € (excl. VAT).</p>	<p>2013</p>
4	<p>Developer - Kaunas DH company Kauno energija – Noreikiškės boiler-house</p> <p>It's the unique boiler-house in Lithuania, adjusted to burn various types of fuel, such as wood chips, sawdust, straw, sewerage biogas from water treatment installations, natural gas and heavy fuel oil.</p> 	<p>Boiler – 4 MW</p>	<p>Total investment – 1.8 million € (incl. 0,67 million € from Lithuanian Environment Fund)</p>	<p>2014</p>
5	<p>Developer E-energija – UAB „Petrašiūnų katilinė“ (is now</p>	<p>2 boilers x 8 MW + 3.2 MW condensing economiser - total 19.2 MW</p>	<p>Total investment over 6 million €, incl. 1.73 million € from EU SF.</p>	<p>2014</p>



	<p>being purchased by Kaunas DH company)</p> <p>During heating season, it consumes approximately 600 m³ of wood chips daily.</p> <p>Produces up to 10 % of the heat necessary for Kaunas City during the heating season and nearly 1/3 of the heat necessary for the production of hot tap water.</p> <p>20 new jobs established.</p> 			
6	<p>Developer - Kaunas DH company Kauno energija - Petrašiūnai CHP</p> <p>Produces up to 12 % of the total heat demand in Kaunas City.</p> 	<p>Heat capacity –</p> <p>2 x 12 MW biomass water heating boilers + 6 MW condensing economiser – total 30 MW.</p>		2014
7	<p>Developer Enerstena - Kauno energija Inkaras boiler-house</p> <p>10 % of the total heat demand in Kaunas City.</p> 	<p>Heat capacity –</p> <p>2 x 8 MW boilers + 4 MW condensing economiser – total 20 MW.</p>	<p>Total investment – 4.93 million €, incl. VAT (in this EU SF supports up to 1.74 million €)</p>	2015

Total biomass heat capacity: 106.7 MW

Table 3.19: New biomass boiler-houses developed by independent energy producers.

No.	Boiler-house information	Capacity	Investment	Year
1	<p>UAB GECO Kaunas boiler-house Fuel – wood chips, cutting residues Designer – “Energetikos linijos”. Installation producer – Enerstena. Facade design – architect-designer Algirdas Kaušpėdas group.</p> 	<p>Boiler capacity – 5.2 MW, Heat capacity –</p> <p>2 x 8 MW boilers + 4 MW condensing economiser – total 20 MW.</p>	5.79 million €	2012
2	<p>UAB Lorizon Energy – developer UAB Naujoji šiluma</p> <p>Boiler efficiency 88.1 %. Flue gas cleaning is via cyclones, chimney height 30 m, diameter 0.90 m.</p> 	10 MW	3.9 million €	2013
3	<p>UAB SSPC – Taika Biomass CHP plant Installation parameters - 90 bar, 500 °C.</p> 	20 MW _{th} + 5 MW _{el}		2014
4	<p>UAB „Oneks Invest“, 2 blocks Fuel - biomass 60%, peat - 40%. Annual fuel consumption up to 170,140 tons (wood chips, cutting residues, total annual heat generation – up to 400 GWh.</p>	<p>Boilers 2 x 19.5=39 MW, + condensing economizers 2 x 4.75=9.5 MW, Total 48.5 MW</p>		2014

				
5	<p>UAB „Foksita“ Biomass CHP plant</p> 	<p>thermal – 38 MW_{th} + power 4.99 MW_{el}</p>		2015
6	<p>UAB „Ekopartneris“ (Kautra) Flue gas cleaning: multi-cyclone, electrostatic filter. Fuel storage 5 m underground with an automatic transportation line. Annual production approx. 120 GWh of heat. Fuel consumption approx. 50,000 t of wood waste.</p> 	<p>2 x 7 MW=14 MW biomass boilers + 3.5 MW condensing economizer = total capacity 17.5 MW.</p> <p>Besides additional CHP installation with capacity - 160 kW_{el} and 180 kW_{th}</p>	5.9 million €	2015
7	<p>UAB „Aldec General“</p> 	<p>2 x 8 MW biomass boilers.</p>		2014
8	<p>„Danpower Baltic“ – biomass CHP. The first investment of „Danpower GmbH“ in Lithuania. 84.9% shares of „Danpower GmbH“ belong to Hannover Municipal „Stadtwerke Hannover AG“ company „Enercity“.</p>	<p>20 MW_{th} + 5 MW_{el}</p>	20 million €	2016

				
9	<p>Kaunas CHP plant</p> <p>Fuel – Municipal solid waste (MSW) after secondary sorting. This capacity allows it to produce up to 30% of Kaunas' heating needs.</p> 	<p>The power plant's boiler has a heat capacity of 85 MW_{th} and can produce a total of 70 MW_{th} of heat, while the steam turbine's electric generator has a capacity of 24 MW_{el}</p>		2020

Total biomass heat capacity: 275 MW

3.4.4 Expectations: Predicted energy output, cost savings, scalability

The Kaunas City Program for Development of Heat Sector for Years 2014-2020 envisaged 180 MW of new biomass installations by 2020. Kauno Energija has even more ambitious plans - with support for investment from EU Structural Funds, it has defined a rather bold challenge – to achieve 85% of biomass in the annual fuel balance. Since the decision on the construction of a waste incineration plant in Kaunas Free Economic zone, the final target was to produce 100% of heat using renewables.

One of the objectives was the reduction of heat tariffs for consumers, mainly residents of multi-apartment residential houses. Constant reduction of heat tariffs is notified while implementing biomass conversion projects. This could be considered as the great success of the implementation; however, the distortion of the market due to installed overcapacities, and the challenge of the new waste incineration plant, which is operating since 2020, does not appear to be optimistic trend for further reduction of heat tariffs, which is due to the growing prices for biomass and not clear situation in future. The energy crisis of 2021 has also added to growing heat costs (Figure 3.19).

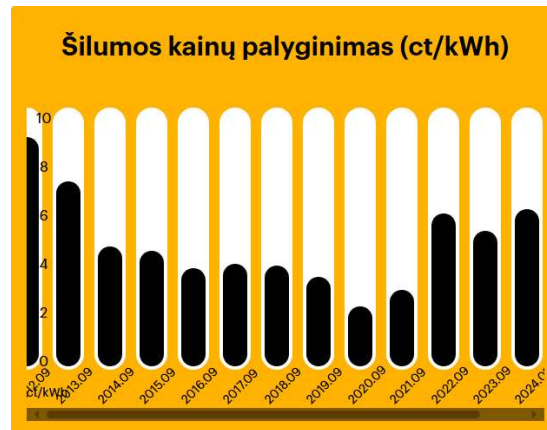


Figure 3.19: Heat costs dynamics (excl. VAT).

3.4.5 Challenges: Risks and mitigation

There are currently 11 independent producers in the integrated network of Kaunas City. The technical problem is that these companies constructed their generating sources, wherever they had plots and possibilities to connect to the grid with the least costs, which is based on business logic. However, in terms of network development, these locations were not optimal or reasonable in engineering terms. The whole system became defragmented, and pipelines are operating in non-favourable conditions in terms of temperature and hydraulic regime. Sustainability and safety regimes are not cared for. Thus, in general, introduction of independent producers has its advantages and drawbacks, which can be defined as follows.

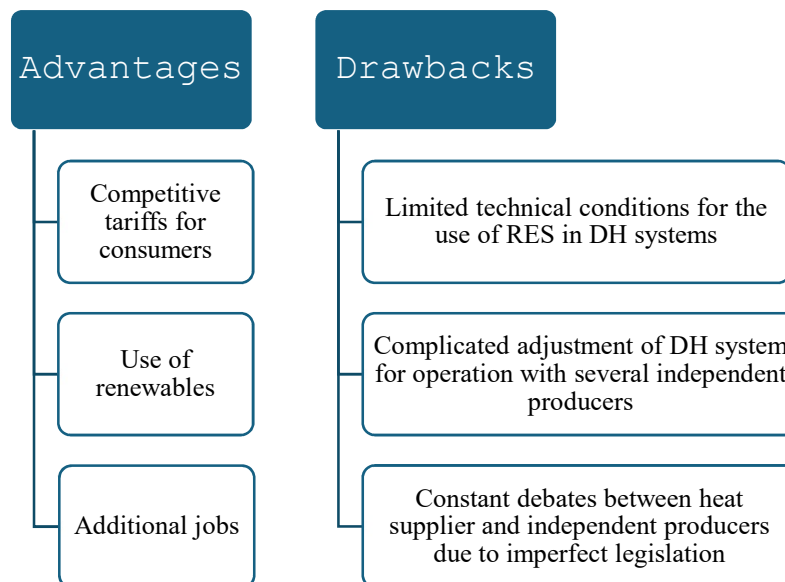


Figure 3.20: Advantages and drawbacks of involving independent producers (IP).

Possible solutions for solving technical problems:

- Heat accumulation with storage tanks:
 - All producers operate in basic mode,
 - Excess heat is accumulated in a storage tank (appr 1 million € investment),
 - Changes in legislation regarding basic, peak and excess energy costs.
- Use of natural gas sources:

- Does not require investment,
- Needs clear regulation on the reservation of a certain share of heat for gas sources,
- Introduction of CHP of high efficiency and respective capacity (appr. 70 MW_{th}):
 - The transfer of the experience of small towns (similar capacities) to large cities makes the operation of DH systems complicated.
 - Introduction of a large CHP would enable simpler operation of the DH system and stability of its parameters.

3.4.6 Impact Assessment: CO2 reduction, job creation, social acceptance

The EU Structural Funds support envisages very few environmental criteria for RES planning, including planned CO₂ savings, CH₄ savings (for biogas). In case of larger projects (over 20 MW), planning envisages an Environment and social impact analysis study, which requires assessment of a larger group of aspects and criteria, which usually are as follows:

- Environment: water, environmental air, soil, biodiversity, landscape,
- Social-economic environment,
- Ethnic-cultural environment,
- Human health.

Regarding climate mitigation, Kauno energija has significantly reduced the use of fossil fuels, emissions of CO₂ and other greenhouse gases into the environment. Nearly 90 % of the supplied heat is generated using renewable energy – biomass. 12 biomass installations in Kaunas City, Kaunas District municipalities, as well as 9 independent producers ensured the covering of 90 % of heat demand.

New independent producers have created a significant number of jobs. The use of renewable energy appears to be acceptable not only for district heating consumers but also for the rest of the community.

3.4.7 Policy and Regulatory Considerations

One of the goals of Lithuania's national energy strategy is to achieve CO₂-free heat production by 2050. Kauno Energija is actively contributing to this goal by implementing fewer polluting technologies and applying preventive measures. Spatial planning for renewable energy on the municipal level in Lithuania is defined by the following legislation:

1. The Law on Renewable Energy Sources of Lithuanian Republic (LR) (XI-1375) by assigning the functions, defined in Article 12, empowering Municipalities to develop the use of renewable energy.
2. The Municipal law of LR (I-533) defines the function of planning and arranging heat provision in the area of the Municipality and using RES in municipal public buildings.
3. The Heat Law of LR (IX-1565) defines the national requirement for developing a National Development Program for the Heat Sector, including the use of renewable, residual energy sources and municipal waste, defining financing needs and financial sources.
4. The Law on Spatial Planning (I-1120) defines the requirement for municipalities to develop special plans, which define existing and planned new areas of heat consumers and provide the principal technical solutions for the use of alternative energy and fuel for every specific area.
5. The Environmental Impact Assessment Act for the Planned Economic Activity (I-1495) requires selection for environmental impact assessment among others for thermal plants, incineration plants and other industrial installations for the generation of electricity, steam or water heating, when capacity is over 20 MW.

There are several support sources for the implementation of investment in the district heating sector:

1. For large projects (over 10 MW) - support for investment from EU Cohesion Funds under Cohesion Promotion Actions programme, Environment and Sustainable Development priority – the Use of Renewable Energy Sources for Energy Generation action;
2. For small projects (under 10 MW) – support from:
 - a. Lithuanian Environment Protection Investment Fund Programme;
 - b. Climate Change Special Programme;
3. Own funding of the district heating company;
4. Municipalities can partly subsidise projects as the main stakeholders of municipal DH companies.

3.5 IWEN: Surplus heat from hydrogen production

Currently, hydrogen is primarily produced through steam reforming. This chemical process involves producing hydrogen from carbon-containing raw materials, such as natural gas (methane), under conditions of high temperature and pressure. This process generates waste heat between 200 and 1000 °C. In practice, this heat can be used by coupling a steam turbine or a combined heat and power (CHP) system. In addition to hydrogen, steam reforming produces CO₂, meaning this process produces grey hydrogen. The following section will focus on the production of green hydrogen and the use of the waste heat generated in these processes. Green hydrogen production and district heating (DH) systems play a key role in a sustainable energy system. Combining these two technologies offers great potential. Green hydrogen can be produced using electrolysis technology which are supplied with electricity from renewable energy sources. In this process, water is split into its two components, hydrogen and oxygen by applying an electrical voltage. In addition to the two product gases this process generates 20 to 40 percent waste heat which can be used for DH systems and in contrast to steam reforming, water electrolysis does not result in the emission of carbon dioxide.

The variety of water electrolysis processes is determined by the electrolyte material utilized. In context of technical applications, three processes have proven to be of relevance. The most mature electrolyses process is alkaline electrolysis (AEL), which is also the oldest. This process utilizes a liquid electrolyte of a basic nature such as potash lye (Potassium hydroxide). An alternative technology is acid electrolysis, which uses a polymer solid electrolyte known as Nafion 117. This process is also referred to as polymer electrolysis (PEMEL). The third technically relevant variant is the high temperature electrolysis, which uses a solid oxide as the electrolyte. This is also the origin of the term solid oxide electrolyser cell (SOEC). For a systematic comparison of these three electrolysis processes the next table presents the main technical characteristics of each technology. The values presented in Table 3.20 have been derived from literature and from the information provided by manufacturer [12, 13, 14, 15, 16].

Table 3.20: Comparison of different electrolysis processes.

Technology	AEL	PEMEL	SOEC
Operating temperature [°C]	40 – 90	30– 100	650 – 1000
Operating pressure [bar]	10 - 30	20 – 50	1 – 15
Current density [A/cm ²]	0.25 – 0.45	0.5 – 2.0	0.3 – 1.0
Load flexibility [%]	20 - 100	0 - 100	0 - 100
Life time [h]	55000 - 120000	60000 - 100000	8000 - 20000
Degradation behaviour [%/a]	0.25 – 1.5	0.5 – 2.5	3 - 50
Stack efficiency [%]	63 – 71	60 – 68	100
Warm start-up time [s]	60 – 300	< 10	900
Cold start-up time [h]	1 – 2	0.083 – 0.167	hours
Technology status	Commercial (mature) TRL 9	Commercial (mature) TRL 8-9	Pre-commercial (R&D) TRL 5-6

While AEL and PEMEL have already been implemented in commercial settings, SOEL remains in the research phase. Due to the elevated operating temperature, SOEC systems are frequently utilized in conjunction with CHP machines to capitalize on the waste heat. However, even the low-temperature

processes of AEL and PEMEL generate a substantial amount of waste heat that can be utilized for DH networks.

In recent years, several demonstration and research projects in Europe have begun to explore how the low-grade heat released by water electrolysis can be integrated into DH systems. Electrolysers, particularly AEL and PEM units, release significant amounts of heat in the 50–80 °C range, which is often dissipated through cooling systems. Turning this by-product into a usable energy stream could improve the overall efficiency of hydrogen production while simultaneously providing renewable heat to cities.

The German IntegrH2ate project [17], led by Fraunhofer IEG, is at the forefront of this field. A real-scale facility is currently being built in Zittau where waste heat from a PEM electrolyser will be captured, upgraded via a high-temperature heat pump, and injected into the municipal district heating grid. The project does not only address the technical feasibility of continuous heat recovery but also investigates the valorisation of oxygen, another co-product of electrolysis [18]. By testing the full chain from hydrogen generation to district heat integration, IntegrH2ate serves as a blueprint for coupling power-to-hydrogen with urban heating networks. The pilot plant is equipped with a 250-kilowatt electrolyser. After the waste heat has been upgraded by the heat pump, it is expected that around 240 megawatt hours of heat can be fed into the Zittau supply network each year – provided that the electrolyser in the laboratory plant is operated economically (around 2,400 full-load hours) [19].

At the international level, the HY2HEAT project [20], coordinated under the International Energy Agency (IEA Technology Collaboration Programme on District Heating and Cooling, DHC Annex XIV) and led by Austrian partners, is examining integration concepts, economic assessments, and policy barriers for electrolyser waste heat. Its analyses demonstrate that direct preheating of DH return flows with electrolyser waste heat can significantly enhance the performance of downstream heat pumps – improving their coefficient of performance by more than 100% in favourable cases and reducing required capacity by up to 50%. The economic modelling shows that DH operators could reduce levelized heat costs by as much as 23% when electrolyser waste heat is effectively integrated. Barriers remain in the form of infrastructure proximity, variable operation linked to volatile electricity markets, and the lack of standardized regulatory frameworks for heat sales.

Practical experience already exists. In Esslingen, Germany, the “Neue Weststadt” district employs a 1 MW electrolyser whose ~55 °C waste heat is fed directly into a neighbourhood network, covering base heating and hot water demand [21]. This raises the overall efficiency of the system from around 60% to more than 80%. Such examples illustrate how low-temperature networks are particularly well suited to capture electrolyser heat without further upgrading.

Broader assessments, such as those conducted within HY2HEAT and other studies, estimate that electrolyser waste heat could cover up to 12% of Austria’s DH demand by 2030, provided that modern low-temperature grids are deployed [15]. While technical feasibility is no longer in doubt, the key challenges lie in ensuring spatial proximity between electrolysis and DH pipes, developing appropriate storage solutions to buffer intermittent hydrogen production, and creating clear contractual frameworks for valuing and trading waste heat.

Table 3.21: Key Demonstration Projects on Electrolyser Waste Heat for DH.

Project / Site	Country	Electrolyser Type & Size	Waste Heat Temp.	DH Integration Concept	Status
IntegrH2ate (Zittau)	Germany	PEM, pilot scale	~60–80 °C	Heat pump upgrades waste heat before injection into DH grid	Pilot under construction (2024–25)

HY2HEAT	Austria	AEL & PEM (modelled)	50–80 °C	Preheat DH return and/or integrate with heat pumps	Research project (2023–26)
Neue Weststadt (Esslingen)	Germany	PEM, 1 MW	~55 °C	Direct feed into low-temp DH network	Operational since 2021

3.5.1 Fundamental Technology: Principles, maturity, and application in DH

In general, electrolysis is the splitting of water into hydrogen and oxygen. For this, an electrolysis cell is required, which is supplied with water and connected to a voltage source. For the assessment of waste heat, the direct current (DC) efficiency of the electrolyser can be used. This parameter indicates how much of the supplied electrical energy is converted into usable chemical energy as hydrogen. The DF efficiency is the difference between the electrical and the chemical energies which then represent the theoretical waste heat of this process.

As shown in Table 3.20, both low-temperature electrolysis methods AEL (TRL 9) and PEMEL (TRL 8-9) are fully mature and already deployed (TRL 8: system complete and qualified; TRL 9: actual system proven in operational environment).



Figure 3.21: Planned location of the electrolyser at the Rostock Overseas port next to the coal-fired power plant. The 7-hectare facility will be in close proximity to already existing infrastructure (pipelines, roads, etc.).

The low operating temperatures of PEMEL and AEL result in limited waste heat recovery. While the waste heat from low-temperature electrolysis technologies such as AEL and PEMEL (approximately 70 - 80 °C) is in principle well suited for 4th generation district heating (typically 50–70 °C supply temperature), many existing district heating systems still operate at considerably higher temperature levels. For example, the

district heating network in the city of Rostock operates at a feed-in temperature of around 110°C. In such cases, the integration of heat pumps is imperative to elevate the temperature level. This coupling facilitates the utilization of low-grade waste heat while ensuring compatibility with the higher operating parameters of conventional district heating infrastructures.

3.5.2 Case Study Details: Location, design, capacity, and stakeholders

The HyTech Hafen Rostock project envisions a 100 MW green hydrogen electrolyser to be constructed at the Rostock Overseas Port site, located at the former coal-fired power plant facility (see Figure 3.21). This location promises direct port access and logistical integration favourable for industrial hydrogen use and future export. The project is being developed under the banner of HyTech Hafen Rostock and is being spearheaded by a newly formed joint venture called rEPco (rostock EnergyPort cooperation GmbH), comprising four partners: RWE Generation SE, EnBW Neue Energien GmbH, RheinEnergie AG, and Rostock Port GmbH. Each partner holds just under a 25% stake in the venture [22, 23]. The plant is scheduled for commissioning in 2028, contingent on a positive investment decision anticipated by mid-2026. The hydrogen produced is expected to serve both local industrial and mobility demand and to be fed into Germany's emerging Hydrogen Core Network (planned to become operational in 2028).

The project has been selected under the IPCEI (Important Project of Common European Interest) Hy2Infra programme and is set to receive funding of approximately € 199 m. from federal and state government sources. Germany's federal government will provide 70% of funding, with the remaining 30% contributed by the state of Mecklenburg-Western Pomerania [24].

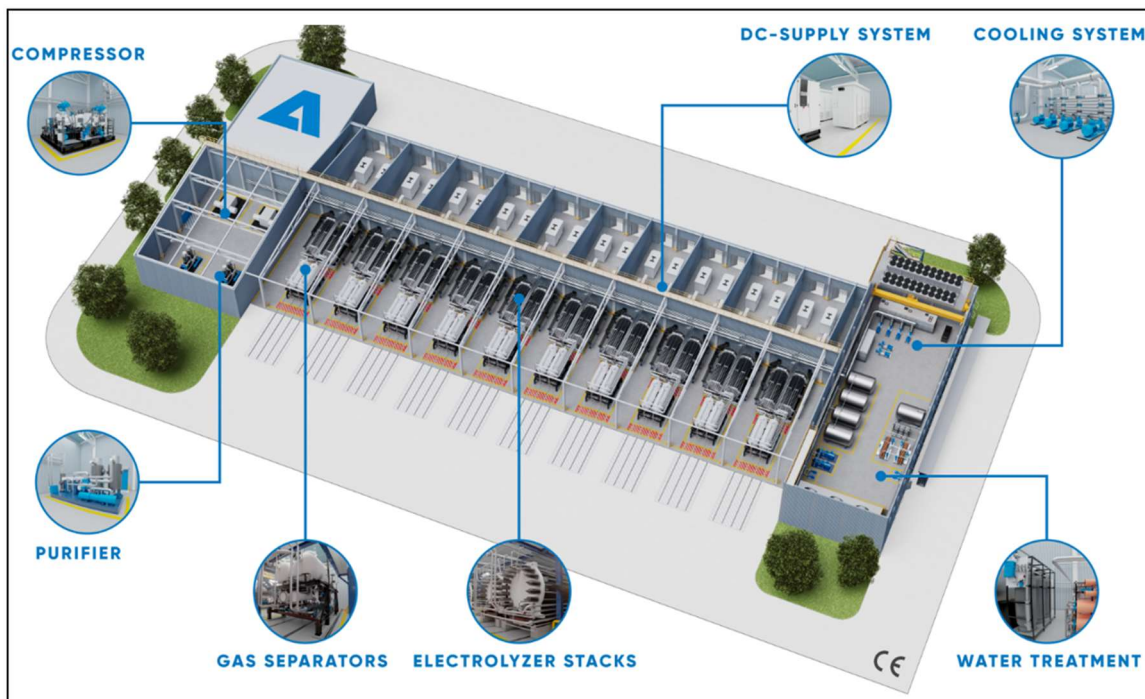


Figure 3.22: General layout of the electrolysis plant according to Andritz AG [25].

The plant will be built on an EPC (Engineering, Procurement, and Construction) basis by ANDRITZ AG, using HydrogenPro's pressurized alkaline electrolysis technology [26]. The supply scope includes not only the core hydrogen production system but also off-site utilities, hydrogen purification, compression systems, storage facilities, and a hydrogen filling station.

The electrolyser's nominal capacity is 100 MW_{el}, with an annual production expected in the order of 8,000-10,000 tonnes of green hydrogen. Contrary to what is shown in Figure 2, eight HydrogenPro Standard modules, with two stacks each, will be installed in the electrolysis hall. In total the electrolyser has a normal H₂ flow of 20000 Nm³/h and a flow range of 40-100% [27, 25].

3.5.3 Integration Plan: Technical steps, infrastructure requirements, timeline

Following engineering and permitting, rEPco plans a final investment decision (FID) in mid-2026. Upon a positive FID, EPC contractor ANDRITZ will proceed using HydrogenPro's pressurised alkaline technology. The EPC scope comprises the core electrolysis trains and key off-sites (hydrogen purification, compression, on-site storage, and a hydrogen refuelling/filling facility) together with balance-of-plant utilities and integration. As a first-mover plant, HyTechHafen is designed to interface with the national Hydrogen Core Network (HCN) and ultimately the European Hydrogen Backbone, requiring interconnection facilities and operating procedures aligned with these systems.



Figure 3.23: National approved Hydrogen Core Network (HCN) of over 9000 km length. The green solid lines (~56%) show existing pipeline segments which will be converted to transport H₂ while the green dashed lines (44%) show the pipelines to be built in the future.

Germany's HCN is the federally approved backbone for hydrogen transport. The federal network agency Bundesnetzagentur (BNetzA) approved the application on October 22, 2024: 9,040 km of pipelines (\approx 56 % conversions and 44 % newly build), with expected investment of € 18,9 bn. and targeted commissioning of the core network by 2032 [28]. GASCADE is a program partner of the European project of common interest (PCI) "Flow – making hydrogen happen" which wants to establish a high-performance north-to-south corridor [29]. The route explicitly lists "Rostock – Lubmin – Schwedt – Berlin – Leipzig – Leuna – Erfurt – Ludwigshafen – Karlsruhe – Stuttgart," (see Figure 3) aiming for a realized transport route by 2029, largely through conversion of existing gas pipelines starting in 2025. Flow targets feed-in capacity up to 20 GW, including imports via Rostock Port and the Baltic Hydrogen Collector [30].

A pivotal element for northeastern Germany is the Rostock – Wrangelsburg (Lubmin area) hydrogen pipeline, planned and promoted by GASCADE as part of the Flow system. On 24 February 2025, GASCADE announced the start of mapping work along the planned corridor (surveying, geotechnical and environmental studies) to prepare the planning-approval procedure through autumn 2025. The line is planned at roughly 120 km (see inset of Figure 3.23), designed to receive hydrogen in the Rostock port area and connect onward via Flow; completion is targeted for 2028 [31].

3.5.4 Expectations: Predicted energy output, cost savings, scalability

The energy yield of low-temperature electrolysis is contingent upon the hydrogen produced, wherein the energy is stored chemically. Furthermore, the proportion of waste heat generated during this process can be calculated. It should be noted that our thermal energy analysis exclusively pertains to the reactions inherent to the cell, stack, and module, while omitting the components necessary for the operation of an electrolysis cell, collectively known as the balance of plant. The operation of the balance of plant components generates additional waste heat, which can be utilized for district heating networks.

By simulating a 100 MW alkaline electrolyser (based on the technical data of HydrogenPro see Chapter 3.5.2) over one year, we calculate reference values for hydrogen production and the amount of waste heat. Upon commission, the electrolyser will be connected to the grid of transmission system operator 50Hertz and will thus use grid power for production operations. However, in this case study, we focus on the potential of renewable energies in the Baltic Sea region for hydrogen production. We therefore consider the curtailed offshore wind energy in the 50Hertz control area for the year 2024. To estimate the curtailment capacity of offshore wind energy in the control area, the individual offshore wind farms were first identified, including their locations and the types of wind turbines installed. Based on local wind data for 2024 provided by the German Weather Service [32], the power output of each wind farm was calculated. Summing up the results gave the overall power curve of offshore wind generation. In a second step, actual feed-in data from the Smard platform [33] was used to show how much offshore wind energy was delivered to the grid during the same period. By comparing the two curves – the potential generation and the actual feed-in – the amount of curtailed offshore wind energy throughout 2024 could be identified. This value then serves as input for the simulation while also controlling the operation status of the AEL. Our simulations show that the electrolyser can run at its maximum capacity for nearly 6 months per year (4141 h). Additionally, it is working 454 h between the power range of 40% and 100 %. This process generates 8900 tons of hydrogen and approximately 150 GWh of waste heat. For the rest of the year (4189 h) the electrolyser is switched off because the curtailed offshore wind energy is not sufficient for operation. The waste heat generated is available for further use at a temperature level of around 55 °C. In order to use this waste heat for DH networks, it must be raised to a higher temperature level. This can be achieved by using a heat pump. The MATLAB model used for the simulation is explained in more detail in the following paragraph.

The input values for the simulation are the curtailed power produced by wind turbines that is not used for grid feed-in. First, the simulation reads the hourly curtailed generation from a CSV file and builds a time vector. The electrochemical basis is the i - V equation of an electrolyser cell which can be found in the literature [34, 35]. The basic equation for operation of an electrolyser is as follows

$$V_{cell} = V_{rev} + V_{act} + V_{ohm} + V_{conc}$$

The reversible cell voltage, V_{rev} can be derived from the Nernst-equation and the other terms represent activation, ohmic, and concentration overpotentials. This provides the link between current density, cell voltage, efficiency, input power from wind, and total power. The scenario under consideration assumes flexible operating behaviour, which is additionally controlled by ramp behaviour. In practice, the applied voltage must be higher than the theoretical minimum, V_{rev} , because internal resistances and overpotentials occur in the cell. In low-temperature electrolysis processes such as AEL or PEMEL, this additional voltage ensures stable operation and continuous hydrogen production.

The code enforces a minimum load threshold of 40%, interpolates the specific energy consumption between 40% and 100% load, and computes the hydrogen production accordingly. The time span of one single time step is 1 hour. For each timestep, the model receives an input power and calculates chemical power (hydrogen energy output), thermal losses, efficiencies, and total hydrogen mass. In essence, the model requires as input: (1) curtailed wind power data, (2) electrochemical constants, (3) stack design parameters, and (4) specific energy consumption values from literature. These allow mapping between electrical input, hydrogen production, waste heat production, and ramp-constrained operating dynamics.

Our simulation-based results for the amount of waste heat should be understood as rough estimates. It is important to note that not all waste heat can be utilized, as some is dissipated. Furthermore, additional waste heat can be recovered in this process by taking the balance of plant components into account, which were not included in this simulation.

An electrolyser stack consists of many individual cells connected in series. Connecting several stacks in parallel creates electrolysers with capacities of 100 MW, for example. The modular design of an electrolyser stack also allows for increased capacity when needed.

3.5.5 Challenges: Risks (resource variability, drillings costs) and mitigation

Electrolysers tied to variable renewables face low/volatile capacity factors and revenue risk. This is a central theme of recent Global Hydrogen Review 2024 by the International Energy Agency (IEA) [36]. Flexible, part-load operation and portfolio approaches (grid-connected + PPAs, temporal optimisation, storage) are the standard mitigations. The IEA documents rising cancellations/delays and stresses the need for demand creation, flexible operations, and reliable renewable supply to keep projects bankable. For Germany/Europe, this means securing firm grid connections, structured PPAs, and operating the plant dynamically to track prices and RES output.

Until the HCN reaches the port of Rostock, volumes must go to local/nearby offtakers (mobility/industry). BNetzA set an initial, nationwide “ramp-up tariff” of € 25 per kWh/a for core network entry capacity (indexed, reviewed every three years), which reduces commercial uncertainty but still requires alignment of plant start-up with pipeline readiness [37].

3.5.6 Impact Assessment: CO₂ reduction, job creation, social acceptance

A coal-fired power plant, like the one supplying the city of Rostock, would produce around 92000 tons of CO₂ with a heat output of 150 GWh. This is equivalent to the amount of heat an electrolyser would produce in one year without emitting carbon dioxide. In addition, the construction and operation of the electrolyser will generate further jobs.

3.5.7 Policy and Regulatory Considerations

The project aligns closely with EU's current framework. Under the revised Renewable Energy Directive (RED III), member states must ensure at least 42% of hydrogen used in industry is renewable (Renewable Fuels of Non-Biological Origin, RFNBO) by 2030, rising to 60% by 2035, with a minimum 1% RFNBO share in transport by 2030. These targets sit under the broader 2030 renewables goal (42,5% binding; 45% ambition) and the REPowerEU Hydrogen Accelerator (10 Mt H2 domestic + 10 Mt H2 import by 2030) [38, 39, 40].

The Commission's RFNBO Delegated Acts set operational rules what qualifies as "renewable hydrogen." The Definition/Additionality Act requires temporal and geographic correlation between renewable power and H2 production. From January 2030, an hourly correlation applies and location must satisfy the specific bidding-zone or interconnection criteria (until then, a monthly period is allowed). Additionally, the GHG methodology act defines how to calculate life-cycle emissions for RFNBOs [41, 42]. Further, the EU Hydrogen & Decarbonised Gas Market Package Directive (EU) 2024/1788 and Regulation 2024/1789 create common rules for hydrogen network: unbundling principles, third-party access, capacity allocation, and tariff frameworks for dedicated H2 systems [43, 44]. The primary goal is to promote low-carbon fuels in the energy transition by providing a robust and consistent framework for assessing their climate impact. This helps ensure that only fuels with genuine GHG emission reductions are recognized. A key aspect of that package is that member states may apply tariff discounts for renewable gases to accelerate uptake.

In 2022, the European Commission launched the European Hydrogen Bank with its auctions acting as a financing instrument to establish an initial H2 market [45]. The second domestic auction (closed February 2025) selected 15 projects for € 992 m. (two of them are the Kaskade project in Wilhelmshaven and the H2-Hub in Lubmin) [46]. A third auction for up to € 1 bn. is planned for late 2025. Germany complements this with H2Global, a double-auction mechanism implemented by the HINTCO GmbH that bridges the gap between the H2 supply contracts and demand auctions [47, 48].

On the national level, Germany's National Hydrogen Strategy (NHS, updated in 2023) raises the 2030 electrolysis target to 10 GW, expands import instruments, and prioritises industrial decarbonisation [49]. For the HCN, the national government secured EU state-aid approval of €3,2 bn. under the H2Infra programme [50].

3.6 LNU: Biochar used as carbon sink co-produced from existing biomass-fired heat-only boiler system

3.6.1 Fundamental Technology

Biochar is a carbon-rich, porous solid formed when biomass is thermochemically decomposed in an oxygen-limited environment, typically at moderate to high temperatures. Its most recognized application lies in agricultural soil amendment, where it improves soil structure, nutrient retention, and water-holding capacity. However, biochar's potential extends well beyond agronomy; it is also a highly stable form of carbon, capable of sequestering atmospheric CO₂ for centuries, thereby functioning as a negative emission technology (NET).

The production process is generally called pyrolysis where biomass is to be heated above 250°C in an oxygen-free or depleted atmosphere. Volatiles and water are driven off and carbon is re-organized in fused aromatic ring structures that are more recalcitrant to decomposition as compared to the carbon compounds in the original biomass. Depending on the need and use of biochar, its physical and chemical properties would highly depend on the choice of the pyrolysis conditions (temperature, retention time and heating rate). Thermodynamically, biochar produced at pyrolysis temperatures exceeding 600 °C is predominantly composed of aromatic carbon structures, making it highly resistant to microbial degradation. Empirical studies suggest that over 80% of the carbon content in such biochars remains stable in soils for more than 100 years [51]. Recognizing its sequestration potential, the Intergovernmental Panel on Climate Change (IPCC) has ranked biochar among the top six NETs, estimating a global carbon removal capacity in the range of 0.7 to 1.8 Gt CO₂ annually [52]. This positions biochar as a strategic option for countries aiming to meet long-term carbon neutrality or net-negative emissions targets.

Industrial biochar production is often done in a stand-alone process (for example, PYREG process) in which the energy required to dry and heat up the biomass is supplied from combustion of pyrolytic vapor or volatiles. However, there is another option to co-produce biochar by modifying the existing moving grate boiler. In moving grate boilers, the fuel is fed onto the grate while the primary airflow is supplied to the bed from below, perpendicular to the grate. Primary air with partial recirculated flue gas gasifies fuel on the grate. Gaseous products from drying, devolatilization and char oxidation move from the fuel bed to the freeboard, where secondary and tertiary air plus partial RFG are supplied to burn the combustible products. The solid char gets fully combustion at the final grate stage. The bottom ash falls into an ash pit at the end of the grate. In our modification concept, air distribution at the final char combustion stage can be lowered or prevented. The solid char products after devolatilization can be removed and quenched as biochar product instead of combusting them into ash.

When integrated into existing bioenergy systems, biochar production offers a multifaceted approach that simultaneously delivers renewable energy, enhances soil health, and enables long-term carbon storage. In particular, coupling biochar production with district heating (DH) systems offers synergetic benefits. District heating networks, especially those powered by biomass combustion, already play a vital role in reducing reliance on fossil fuels in many parts of Europe, including Sweden. By modifying such systems to include a pyrolysis unit, it becomes possible to co-produce biochar (and potentially bio-oil), adding both environmental and economic value streams to the existing energy infrastructure.

3.6.2 Case Study Details: Location, design, capacity, and stakeholders

A small-scale district heating plant serving the space- and hot water heating demand in Kosta (Figure 3.24), a locality in Lessebo Municipality, southern Sweden is used as a case study. This DH system comprises approximately 23 km of distribution network and has delivered approximately 14.8 GWh in 2023. Currently, heat is produced primarily by a 3 MW_{th} heat-only boiler using wood chips. Full-year operating data [53] for the Kosta DH system, covering the period from March 1st, 2023 to February 29th, 2024, was collected from

This scenario models the co-production of biochar and district heating heat output strictly in accordance with the municipality's actual annual heat demand. Biochar is treated as a by-product, with no changes to the plant's current operation mode other than the inclusion of pyrolysis-based conversion.

Scenario 2 – Maximum Capacity Biochar Production:

This scenario assumes the heating plant operates continuously at its full rated capacity (3 MW), irrespective of fluctuating demand. The objective is to maximize biochar production and evaluate the feasibility of operating the system under steady-state full-load conditions. Surplus thermal energy not absorbed by the district heating network is treated as non-utilized waste heat (spill heat).

Scenario 3 – Integrated Biochar and Bio-Oil Production:

This scenario builds upon Scenario 2 by introducing a condensation stage for excess pyrolysis gas. Instead of flaring or discarding surplus heat, pyrolysis gases are partially condensed to produce bio-oil. This scenario assumes idealized condensation efficiency and aims to evaluate the potential for triple co-production: heat, biochar, and bio-oil.

Capital expenditures (CAPEX), operational expenditures (OPEX), and projected revenues were estimated based on data from the Danish Energy Agency and adjusted for the specific scale and configuration of each scenario. The financial analysis included:

- Payback period calculations under interest rates of 0%, 5%, and 10%.
- Return on Investment (ROI) over a 25-year operational period.
- Two repayment models: a traditional “payback” approach using annual profits, and an “annuity” method distributing repayments evenly over time while accounting for interest.
- Product revenues were assumed constant and calculated from average market values: €350 per ton of biochar and €651 per ton of bio-oil. District heating prices were based on published data from the Lessebo plant.

The techno-economic analysis demonstrated promising financial outcomes across all three modelled scenarios. Calculated median payback periods (see Figure 3.25) indicate that the initial investment for the pyrolysis retrofit could be recovered within relatively short timeframes—approximately 1.7 years for Scenario 1, 3.4 years for Scenario 2, and 2.4 years for Scenario 3, under a normal interest rate of 5%. These short payback periods reflect both the high economic efficiency of the system and the favourable market conditions for biochar and bio-oil within the assumed pricing frameworks.

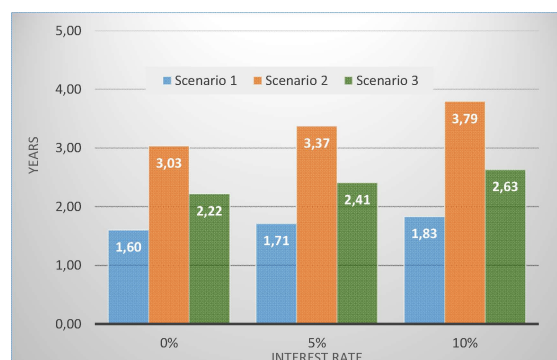


Figure 3.25: Payback time estimated under different interest rates for three scenarios.

Beyond the favourable economic performance, the environmental benefits of retrofitting biomass boilers for biochar production are considerable (see Figure 3.26). The environmental potential of each scenario was

assessed through estimation of carbon dioxide sequestration via biochar. The factor of 2.5 tons CO₂ per ton of biochar was used, based on national biochar guidelines [54]. Scenario 1 achieved an estimated sequestration of 3,650 tons of CO₂ per year, aligning with moderate production levels tied to actual heat demand. In Scenarios 2 and 3, where the system operated continuously at full thermal capacity, the annual sequestration potential rose substantially to 8,400 tons of CO₂. These results underscore the climate mitigation potential of slow pyrolysis retrofits, positioning district heating plants not only as energy providers but as net carbon sinks. It is important to note that these estimates reflect only the carbon sequestered in biochar and do not account for upstream emissions (e.g., biomass harvesting and transport) or process emissions. However, given the long residence time of stable carbon in biochar, especially when applied to soils or incorporated in construction materials, these figures are likely conservative with respect to long-term atmospheric carbon removal [55, 51].

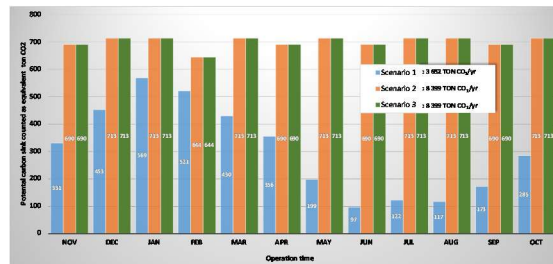


Figure 3.26: Monthly and annual carbon sequestration potential of the district heating plants with biochar co-production under different scenarios.

3.6.5 Challenges

Challenges to biochar as a carbon sink in the EU include ensuring sustainable biomass sourcing to avoid displacing natural carbon sinks, developing robust verification and certification schemes for carbon removal, managing potential environmental risks like increased methane emissions or nutrient leaching, overcoming regulatory hurdles and limitations on state aid, and establishing viable economic models to support production and deployment.

3.6.6 Policy and Regulatory Considerations

The EU supports biochar as a carbon sink under several frameworks, including the European Green Deal, the Common Agricultural Policy (CAP) (which includes soil carbon sequestration), and the proposed EU carbon removal certification scheme for biochar carbon removal (BCR). Biochar's potential is recognized for permanent carbon removal, and its inclusion in the EU Emissions Trading System (EU ETS) is being advocated for by organizations like Biochar Europe.

The European Commission adopted a legislative proposal for carbon removal certification, accompanied by an impact assessment on 30 November 2022. The Commission proposed a Regulation to establish a Union certification framework for carbon removals. The regulation would aim to facilitate the deployment of high-quality carbon removals. Certification would be based on four overarching criteria for which detailed methodologies would be developed through subsequent delegated acts for different carbon removal activities. The criteria are: 1) Quantification, 2) Additionality and baselines, 3) Long-term storage, and 4) Sustainability, for which the Commission uses the acronym Q.U.A.L.I.T.Y.

4 Conclusions and Recommendations

Across the diverse case studies examined in this report, several shared insights emerge regarding the integration of renewable energy into district heating systems. All case studies demonstrated significant decarbonization potential, confirming that a variety of renewable solutions can effectively reduce greenhouse gas emissions in district heating. Each pilot – whether deploying solar collectors, geothermal wells, biomass boilers, wind turbines, or industrial waste heat recovery – showed substantial CO₂ reductions compared to the fossil-fueled baseline. Many cases also reported co-benefits such as improved local air quality and enhanced energy security. By replacing or supplementing fossil fuel use, projects like the solar thermal farm and biomass conversion made heat supply less exposed to fuel price volatility and external supply risks, contributing to more stable and secure heating costs for consumers. Another positive trend is that these solutions relied on mature, commercially available technologies – most of the implemented options are at high technology readiness levels (TRL 8–9) and have been proven in real operational environments. This indicates that the primary components for decarbonizing district heating (solar collectors, heat pumps, advanced boilers, etc.) are already accessible, and the challenge lies in deploying them at scale.

Notably, all the case studies unfolded within an enabling policy context. They were aligned with EU-wide climate and energy goals as well as national strategies and regulations. For instance, projects explicitly cited consistency with the EU Renewable Energy Directive and the European Green Deal targets, and responded to national or municipal mandates for cleaner heat. This common alignment with political frameworks underscores that strong policy support and clear targets at EU, national, and local levels have been critical drivers in initiating and guiding these renewable heating projects. Despite the encouraging outcomes, the case studies also reveal recurring challenges and barriers that were common across different technologies and locations. A foremost challenge is the high upfront investment cost associated with new renewable heating infrastructure. Whether it is deep geothermal drilling, installing large solar collector fields, or retrofitting boilers for biochar production, the initial CAPEX is substantial, often running into millions of Euros. Securing funding and achieving economic viability required careful financial planning, feasibility studies, and in some cases external support or innovative business models.

Another near-universal hurdle has been permitting and regulatory compliance. Projects frequently encountered lengthy and complex approval processes – for example, obtaining the necessary drilling permits and environmental clearances for geothermal installations can be time-consuming, and similarly, building permits or grid connection approvals for solar facilities had to be navigated. Ensuring compliance with construction codes, environmental impact assessments, and other regulations introduced delays or extra costs in several cases. These permitting challenges highlight the need for clearer and faster administrative procedures for renewable energy projects in the heating sector.

In terms of technical and operational challenges, integrating new energy sources into existing district heating networks proved to be a complex task in each case. Partners had to address issues of system compatibility and control – for instance, making sure a solar thermal array or a large heat pump could be smoothly incorporated without disrupting the network's hydraulics or heat balance. In the Wejherowo case, this meant adding plate heat exchangers and upgrading the control/SCADA systems to manage temperature and flow differences, ensuring the solar farm operates in harmony with the existing combined heat and power (CHP) plant. In the hydrogen waste heat case, it became clear that effective use of electrolyser by-product heat depends on spatial proximity (locating the hydrogen production close to the DH network) and developing thermal storage to buffer the intermittent operation of electrolysers. Indeed, resource intermittency is a general challenge for renewables: solar and wind inputs vary with weather, so their integration into heating requires backup arrangements or storage. The case studies addressed this by, for example, coupling solar systems with existing gas/coal boilers or thermal storage tanks to guarantee heat supply during low-sun periods. Wind-powered electric boilers similarly would need grid backup or heat storage to ride through calm periods. Limited land or resource availability was another common issue –

some projects struggled with finding adequate space for new installations or ensuring sufficient sustainable biomass fuel supply for year-round operation.

Lastly, stakeholder and community acceptance factors were noted across the cases. Even though renewable energy is broadly supported, local concerns had to be managed: for example, visual/aesthetic impacts and noise from new equipment were mitigated through design measures in the solar farm project (using low-noise components and visual screening). In biomass-related cases, questions about air emissions and sustainable sourcing of biomass were raised, necessitating transparency and adherence to sustainability criteria. Addressing these social and environmental concerns required early engagement with the community and stakeholders, as well as robust mitigation strategies.

In summary, while each technology had unique hurdles, there was a clear pattern of high capital costs, regulatory hurdles, integration complexity, resource variability, land use constraints, and the need to maintain public support being the key challenges to overcome for successful implementation. Importantly, the political and planning frameworks in the respective countries played a significant role in shaping both the opportunities and challenges. All the case studies benefitted from the fact that they were undertaken in jurisdictions with policies favouring the decarbonization of heating. Common elements included national renewable energy action plans, financial incentive programs, and requirements for municipalities to incorporate renewable and efficient energy in their urban planning. For example, Lithuania's laws mandate municipalities to develop special heat plans that define how renewable and alternative energy sources will be used in their districts. Similar planning mandates and targets exist in Poland, Sweden, Denmark, and Germany, creating an official pathway for projects like these.

On the funding side, EU and government support schemes were a pivotal backdrop: several case studies tapped into subsidies or grants (such as EU Cohesion Funds, green investment programs, or climate funds) dedicated to clean energy in infrastructure. This underscores a shared understanding that public financing or incentives are often necessary to kick-start innovative projects given their high upfront costs. At the same time, differences in local policy conditions also influenced project progress – for instance, where feed-in tariffs or renewable heat obligations existed, projects could more easily justify their economics, whereas in less supportive environments the business case was harder to close. Overall, the need for coherent multi-level governance is evident: projects thrived when local efforts were bolstered by supportive national policy and EU-level strategy, and when they were integrated into official city energy plans or climate targets.

Recommendations

Drawing on the collective findings of these case studies, the following initial recommendations are offered to facilitate the wider deployment of renewable energy in district heating systems:

Streamline Permitting and Regulations: Simplify and accelerate the permitting processes for renewable heat projects. Lengthy approval timelines for installations (e.g. drilling permits for geothermal, construction permits for solar/wind farms) can significantly delay progress. Governments should establish clear, one-stop permitting frameworks and standardized environmental assessment criteria for district heating projects, which will reduce administrative barriers while still upholding safety and environmental standards.

Increase Financial Support and Innovative Funding Models: High upfront investment costs remain a key barrier, so enhanced financial support is crucial. This could include expanded grants, low-interest loan programs, or risk-sharing instruments to de-risk large renewable DH investments. Leveraging EU and national funding schemes (such as Cohesion Funds or climate investment programs) has proven effective and should continue. Additionally, promoting innovative business models – for example, Energy Service Companies (ESCOs) or public-private partnerships – can help utilities manage CAPEX and attract private capital by spreading costs and returns over longer terms.

Integrate Renewable Heating into Energy Planning: It is recommended that municipal and regional energy plans explicitly include decarbonized district heating targets and roadmaps. Aligning local planning with national climate strategies ensures that infrastructure (zoning for solar fields, rights-of-way for pipes, sites for geothermal drilling, etc.) is reserved and optimized for renewable integration. This integration should be supported by policy instruments like mandates for a minimum share of renewables in heating, or requirements for new developments to connect to or install sustainable heat supply. Coherent planning provides certainty for project developers and enables synergies (for instance, linking waste heat sources with nearby heat demand through urban planning).

Engage Stakeholders and Build Social Acceptance: Early and continuous stakeholder engagement is vital to address community concerns and improve public acceptance of projects. The case studies show that when communities understand the local benefits – such as cleaner air, stable heat prices, and job opportunities – support is stronger. Project developers should work with local residents, businesses, and authorities through consultations and transparent communication. Proactive measures (like mitigating noise/visual impacts and ensuring sustainable fuel sourcing) should be taken to respond to concerns, and these efforts should be clearly communicated. Developing local “champions” or reference sites that demonstrate the technology’s benefits can also help in gaining public trust.

Knowledge Sharing and Replication of Best Practices: The experiences from each pilot site should be documented and shared across the industry and municipalities. Replication of successful models will be key to scaling up decarbonization. For example, the solar thermal pilot in Wejherowo was designed as a replicable model for other towns – such reference projects provide valuable templates in technical design, business cases, and operational strategies. It is recommended to organize cross-city and cross-border knowledge exchange so that lessons on what worked and what challenges were encountered can inform new projects. This will accelerate learning curves and avoid “reinventing the wheel” for each new district heating initiative.

Plan for Flexibility and Reliability: To address the inherent variability of some renewable sources, future projects should incorporate adequate flexibility measures (such as thermal storage, backup capacities, or sector coupling). Several case studies highlighted the importance of storage solutions to buffer intermittent supply – for instance, using heat storage to manage the fluctuating output of solar or electrolytic hydrogen systems. Ensuring that district heating networks can handle variable input (through smart controls, storage tanks, or hybrid systems that include auxiliary boilers or heat pumps) will maintain reliability of service. Policymakers and utilities should therefore invest in complementary technologies like heat accumulators, demand-side management, and integrated energy systems as they add renewables to the heating mix.

These recommendations are preliminary and based on the shared observations from the case studies in this report. Going forward, more detailed analyses will be conducted implementing the above measures to create a more favourable environment for renewable integration into district heating. These pilot actions will help to overcome common barriers and accelerate the transition toward low-carbon heating networks across the South Baltic region and beyond. Each success in a pilot municipality can thus be scaled up or transferred, bringing EU countries closer to their climate goals while delivering tangible benefits to local communities.

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