THESIS FOR THE DEGREE OF DOCTOR OF TECHNOLOGY

Solar District Heating:

A Techno-Economic Analysis
for
a New and an Existing District Heating System

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Division of Building Services Engineering

Department of Architecture and Civil Engineering

CHALMERS UNIVERSITY OF TECHNOLOGY

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Cover:

(Top) Schematic of the partly decentralised system in Vallda Heberg, showing a single-family house (SFH) to the left, substation and arbitrary building(s) with roof-mounted collectors (middle) as well as boiler central with roof mounted collectors (right) - see *2.3.1 Distribution systems*.

(Bottom) Schematic of the existing district heating system in Hemse to the left, with a storage in the middle and a solar heating system to the right – see *2.3.3 Existing district heating model*.

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ABSTRACT

The integration of a solar thermal system into a district heating network can be a cost-effective solution, especially for new low-energy residential areas. Because of this, several new small solar district heating systems are built at the same time as the buildings, allowing for a more holistic approach to the design and construction. In doing so, it is possible to optimise the integration of the solar thermal system with respect to both cost and technical layout. When integrating solar into an existing district heating network, the premise for the technical layout is largely set, so the optimisation is limited in scope and is weighed more towards cost aspects, although no less relevant.

This thesis presents studies that aim to investigate the most cost-effective distribution concept for successful implementation of solar heating technology in a new district heating system. A solar district heating system that was built anew and at the same time as the buildings, was modelled in simulation software and the distribution system was varied in order to find out whether there was a more cost and energy efficient option. Three system concepts were investigated: a <u>Hybrid</u> system using a combination of high temperature steel pipes and low temperature plastic pipes and a combination of centralised/decentralised solar heat, a <u>Conventional</u> system using high temperature steel pipes only and centralised solar heat and an <u>All GRUDIS</u> system, using only low temperature plastic pipes and centralised solar heat. Results indicate that when building a new solar district heating system, both a hybrid and All GRUDIS distribution concept is preferable to conventional DH distribution regardless of the network heat density, and although they perform similarly energetically, the latter is economically the best option.

This thesis also present studies that aim to investigate whether or not solar heating can be cost-effective when added to an existing district heating system. A conventional boiler-only district heating system was modelled in simulation software with a real load profile to find out whether it can be cost-competitive with a system where solar heating was added together with a boiler replacement (re-powering) or by itself (retro-fit), for different economic boundary conditions. Results showed that solar heating was cost-competitive and could yield lower heat costs than the conventional system, except when solar thermal system size was small, fuel costs were low and capital discount (interest) rates were high. This was valid both when re-powering and retro-fitting, although the latter resulted in much lower unit heat costs than the former.

Keywords: District heating, solar thermal, PEX, GRUDIS, 4DH.

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SAMMANFATTNING

Integreringen av ett solvärmesystem i ett fjärrvärmenät kan vara en kostnadseffektiv lösning, särskilt för nya bostadsområden med låg energiförbrukning. På grund av detta byggs flera nya små soldrivna fjärrvärmesystem samtidigt som byggnaderna, vilket möjliggör ett mer holistiskt tillvägagångssätt för design och konstruktion. På så sätt är det möjligt att optimera integrationen av solvärmesystemet med avseende på både kostnad och teknisk layout. När man integrerar solenergi i ett befintligt fjärrvärmenät är förutsättningen för den tekniska layouten till stor del satt, så optimeringen är begränsad i omfattning och väger mer mot kostnadsaspekter, även om den inte är mindre relevant.

Denna avhandling presenterar studier som syftar till att undersöka det mest kostnadseffektiva distributionskonceptet för framgångsrik implementering av solvärmeteknik i ett nytt fjärrvärmesystem. Ett soldrivet fjärrvärmesystem som nybyggdes samtidigt som byggnaderna, blev modellerat i simuleringsprogram och distributionssystemet varierades för att ta reda på om det fanns ett mer kostnads- och energieffektivt alternativ. Tre systemkoncept undersöktes: ett <u>hybrid</u>system som använder en kombination av högtemperatur stålrör och lågtemperatur plaströr och en kombination av centraliserad/decentraliserad solvärme, ett <u>konventionellt</u> system som endast använder högtemperatur stålrör och centraliserad solvärme och ett <u>GRUDIS</u>-system, som endast använder lågtemperatur plaströr och centraliserad solvärme. Resultaten indikerar att när man bygger ett nytt solvärmesystem är både ett hybrid- och GRUDIS distributionskoncept att föredra framför konventionell fjärrvärmedistribution oavsett nätverkets värmetäthet, och även om de presterar lika energimässigt är det senare det ekonomiskt bästa alternativet.

I denna avhandling presenteras även studier som syftar till att undersöka om solvärme kan vara kostnadseffektivt när den adderas till ett befintligt fjärrvärmesystem. Ett konventionellt fjärrvärmesystem med enbart panna modellerades i simuleringsprogramvara med en verklig belastningsprofil för att ta reda på om det kan vara kostnadseffektivt med ett system där solvärme tillsattes tillsammans med ett byte av panna (re-powering) eller för sig själv (retro-fit), för olika ekonomiska randvillkor. Resultaten visade att solvärme var kostnadsmässigt konkurrenskraftigt och kunde ge lägre värmekostnader än det konventionella systemet, förutom när solvärmesystemet var litet, bränslekostnaderna låga och/eller kapitaldiskonteringsräntorna var höga. Detta gällde både vid re-powering och eftermontering (retro-fit), även om den senare resulterade i mycket lägre värmekostnader per enhet än den förra.

Sökord: Fjärrvärme, solvärme, PEX, GRUDIS, 4DH.

List of papers

This doctoral thesis is based on the following papers:

Paper I Perez-Mora, N., Bava, F., Andersen, M. et al., Solar district heating and cooling: A review. Int J Energy Res. 2017, 1 – 23. https://doi.org/10.1002/er.3888.

The author wrote the section on block-heating and case-study as well as contributed to the sections of introduction and conclusions.

Paper II Martin Andersen, Chris Bales, Jan-Olof Dalenbäck; Heat distribution concepts for small solar district heating systems – Techno-economic study for low line heat densities, Energy Conversion and Management: X, Volume 15, 2022. https://doi.org/10.1016/j.ecmx.2022.100243.

The author planned the modelling approach and made the simulation model, collected engineering standards on the design of heat distribution networks and carried out all design calculations for the network pipe sizes. The author carried out the simulations, analysed simulation results, did error assessments on the model accuracy and wrote most of the paper. Dr. Chris Bales supported in planning of modelling approach and the application of standards during the design of heat distribution networks and together with Dr. Jan-Olof Dalenbäck evaluated results and supported in the writing of the paper.

Paper III Andersen M, Bales C, Dalenbäck J-O. Economic Analysis of Heat Distribution Concepts for a Small Solar District Heating System. Energies 2022. https://doi.org/10.3390/en15134737.

The author planned the modelling approach, made the simulation model, communicated with suppliers and collected information from industry representatives. The author carried out all simulations and analysed the results, as well as conducting the economic calculations. Dr. Chris Bales and Dr. Jan-Olof Dalenbäck supported in the development of methodology, as well as evaluation of the results and supported during the writing process.

Paper IV Martin Andersen, Chris Bales, Jan-Olof Dalenbäck, Techno-economics of solar re-powering and retro-fitting an existing district heating network, Energy Conversion and Management: X, 2024, https://doi.org/10.1016/j.ecmx.2024.100799.

The author planned the methodical and modelling approach, communicated with suppliers and industry representatives for information on costs and best-practice, made the simulation model, conducted simulation and economic calculations in addition to analysis of results. Dr. Chris Bales and Dr. Jan- Olof Dalenbäck supported in development of modelling and methodical approach, as well as analysis of results and in the writing process.

Submitted to Journal of Energy Conversion and Management: X – July 2024.
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This thesis studies two aspects of solar district heating;

1) The first treats the addition of solar heating to a district heating system being built anew and is based on Paper II and Paper III.
2) The second treats the addition of solar heating to an existing district heating system and is based on Paper IV.

Paper II – Paper IV follow in full text. Only the first 11 pages of the Paper I are included, as this part is the most relevant for the thesis in providing background.

The text in this thesis can largely be considered a continuation of the previously published licentiate thesis[1], which has a similar build-up to a PhD thesis. Therefore, much of the content in this thesis has been published before, with additions from the studies made after the previous thesis publication.

Other papers forming the basis for, but not included in, the thesis:

Paper V Andersen, M., Bales, C., Dalenbäck, J-O., Techno-economic Analysis of Solar Options for a Block Heating System, in proceedings of Eurosun 2016, Palma de Mallorca, Illes Balears, October 2016. doi:10.18086/eurosun.2016.05.12

The author continued the work of another researcher based on a subsystem simulation model calibrated against real measurement data. Planning of the modelling approach was a collaborative effort with Dr. Chris Bales, while the author carried out simulations. The author did the analysis of simulation results and wrote most of the paper, with support from Dr. Chris Bales and Dr. Jan-Olof Dalenbäck.

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Acknowledgements

The journey to become a doctor started 10 years ago and thus, has been a very long one. Many people have been part of the journey in this time, to each whom I owe gratitude for supporting me in one way or another.

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I also extend my gratitude to Per-Erik Andersson Jessen at Andersson & Hultmark for making my secondment at your firm a memorable experience, for always providing me with valuable guidance on engineering practices and for giving every conversation a positive touch. I thank you for always taking me up on lunch and giving me short and precise answers to my ever-expanding list of questions. There should be more of you in every engineering firm.

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Nomenclature

BC	Boiler central
CHP	Combined heat and power
DFO	Diesel fuel oil
DH	District heat(ing)
DHW	Domestic hot water
DN	Nominal diameter
DR	Discount rate
EL	Electricity
EPS	Extruded polystyrene
EPSPEX	EPS encased PEX pipes
ETC	Evacuated tube collector(s)
EUR	Euro(s)
FCI	Fuel cost increase
FPC	Flat plate collector(s)
GRUDIS	Swedish acronym for "GRUppcentral DIStributionssystem"
HFO	Heavy fuel oil
IR	Interest rate
LCC	Life cycle cost
LD	Line heat density (unit heat demand per unit length of heat network)
LTDH	Low temperature district heating
LCOH	Levelised cost of heat
PI	Pre-insulated
PC	Primary culvert
PEX	Cross-linked polyethylene
SC	Secondary culvert
SDH	Solar district heating
SEK	Swedish krone(s)
SF	Solar fraction
SFH	single-family house
SH	Space heating
SS	substation
ST	Solar thermal
TMY	Typical meteorological year
WP	Wood pellet(s)
WPB	Wood-pellet boiler

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1. Introduction

The content in the thesis is divided and described in terms of relevance to newly built district heating systems and existing district heating systems as noted together with the list of papers.

1.1 Background

The background is divided into three sections; The first section treats common background for district heating (DH) in general, the second section treats background necessary for the first part of the thesis related to integration of solar thermal into newly built DH, while the third section introduces new background necessary for the second part of the thesis related to integration of solar thermal into existing DH.

1.1.1 Common background on district heating

DH has been used as an efficient method to generate and distribute heat commercially for many years now. The world's oldest operational DH system is located in Chaudes-Aigues, France. It was put in operation in the 14th century, utilizing geothermally heated water. However, the first commercial system was developed in Lockport (USA) in 1877, utilizing steam as a heat carrier [2]. The first DH systems in Europe and Russia were installed during the 1920s and '30s, all with the aim of reducing the fuel demand and delivering heat more efficiently. This aim was further emphasized by including DH in the new national energy policies adopted by many countries during the oil crises in the '70s [3]. Nowadays, 6 – 7% of the global heat demand [4] and 9% total heating needs in Europe are supplied by community and district heating systems [5].

Fundamentally, the underlying principles of the DH concept is to recycle heat that would otherwise go to waste and to enable a more efficient use of primary energy and hence, natural resources. For these reasons, countries (e.g. Sweden and Germany) that have energy-intensive industries based on processes like metallurgy, petroleum and paper production have traditionally had strong ties to DH. Likewise, countries (e.g. Denmark and Finland) that traditionally have been dependent on fossil-fuel imports have developed equally strong bonds with DH. Geographically, DH systems are most widespread in the northern hemisphere, predominantly (descending order) in Europe (northern and eastern part), Russia, China and North America. Countries like Denmark, Sweden, Finland together with Poland and the Baltic states have the largest market shares (>40%). Eastern European countries generally have many systems, due to the influence of the former Soviet Union, where DH was under development early as part of the planned economies [6].

The resource availability and predominant energy technologies over the course of history has been dictating the heat carrier employed and maybe more importantly, the applied operating temperatures. The first generation of DH technology employed steam as a heat carrier and was characterized by high operating temperatures and distribution heat losses, leading to low overall system efficiency. As the technology evolved, operating temperatures were reduced and pipe insulation practices improved, progressing towards the third generation DH of today. The future, fourth generation DH, continues this trend and further aims to include renewable sources of heat, which are particularly well suited for low-temperature applications like space heating (SH) and domestic hot water (DHW).

1.1.2 Background for new district heating

District heating has always required a certain line heat density, that is as certain amount of heat demand relative to the network length, in order to be economically feasible, which has favoured its use in urban environments and limited its employment in rural and suburban areas. As low-energy building codes are increasingly implemented around the world [4], aiming to reduce energy demand, the heat demand density[1] of DH networks is reduced and distribution heat losses become an increasingly larger part of the network energy use. This is contradictory to the fundamental principles of DH and further undermines its future implementation in suburban areas due to reduced competitiveness versus other heating methods. Thus, research efforts are needed to identify the most efficient distribution options available, in order to establish the potential role of DH in the future sustainable energy system [7].

District heating has a long history in Sweden and early research efforts made into small district heating systems for suburban residential areas indicated that plastic pipe systems held the potential of being a cost-efficient way of extending the urban DH networks [8,9]. An own research project about sparse district heating concluded that using plastic pipes was one way to make low heat density areas more profitable [10], especially if used in a secondary network, adjunct to a conventional steel pipe system [11]. This view was further endorsed in an official research report conducted by the International Energy Agency (IEA), advising that cross-linked polyethylene (PEX) pipes in an evacuated polystyrene (EPS) casing (so called EPSPEX culvert) are suitable for areas of low heat demand density and have the lowest operation costs [12]. Another IEA report went on to recommend the EPSPEX culvert for use in low temperature district heating (LTDH) as envisioned in 4th generation DH [13], a view recently reiterated as an essential improvement in future DH systems [14].

EKSTA Bostads AB is a municipal housing company located in the south-west of Sweden, known for investments in building and operating new residential areas with the requirement of 100% renewable heat supply, the first ones from the 1980s. This is usually done using small district heating systems with bio-mass boilers and roof integrated solar collectors. The building stock is often of the low-energy or passive house standard and various attempts have been made to lower the distribution heat losses and increase solar fractions. In one system, Vallda Heberg, a hybrid distribution concept combines third and fourth generation DH technology by employing both high temperature steel culverts and low-temperature plastic pipes. In light of the promising experiences from this system, the novel distribution concept has been used as a best-case example of renewable DH [15] and may represent a new solar district heating standard for newly built residential areas. Due to this, it is therefore of interest to determine any potential improvements to the system by moving towards a 4th generation system design. This is the premise of the work on new DH presented in this thesis.

1.1.3 Background for existing district heating

Despite the development of distribution technology to integrate low-temperature heat into the DH networks built new, most of the systems in operation both today and in the near future are the existing ones using 3rd generation technology.

The EU and China have the largest shares of DH in the heat supply in the world, but the renewable share is still rather low, except for a few countries like Sweden, Denmark, Iceland, France, Austria and some Baltic countries that have shares above 50%. The renewable heat in these networks is largely supplied by biomass [16] that could be better utilised for other applications, which makes solar heating an interesting option to reduce fuel demand and potentially the carbon footprint. A report by the Swedish Energy Agency states that biomass will increase in value towards 2050 [17], which should incentivise more efficient use and reduction in employment for direct heat applications. Additionally, the use of

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[1] Heat demand density is defined as the unit heat demand per unit area, i.e. TJ/km^2. It is different from line heat density, which is defined as unit heat demand per unit length of heat network.

solar heat could potentially decrease fuel use from backup-boilers during summer maintenance, along with associated emissions, while simultaneously lowering heat costs.

However, the high operating temperatures typically employed in 3rd generation networks, affects the efficiency of particularly the flat plate collector (FPC) negatively, which is thought to limit the suitability [7]. Despite this, the overall share of FPC in installed collector area worldwide has more than doubled the recent years (2011 – 2021), going from 15 – 34%, although the share of FPCs has declined somewhat (-9%) in Europe during the same period. Instead, the evacuated tube collector (ETC) has been gaining ground in Europe and its share of newly installed collector area worldwide has remained high. This might indicate that the market is developing towards collector technology that works better at operating temperatures in existing, 3rd generation networks[18], although there are few known large scale systems, with merely 2% of SDH systems supplied by ETCs in 2019. FPCs have likely been the preferred choice for large scale applications like DH due to economy of scale (i.e. lower cost), installation efforts and durability of FPCs, to name a few [19]. Nonetheless, with the introduction of ETCs designed specifically for use in industry and DH, volume effects from their employment could drive the technology [20]. If this happens, the ETC could represent an attractive alternative to the FPC due to the promise of higher efficiency and increased yield, which could reduce biomass fuel consumption even more.

The district heating system in Hemse, Gotland, Sweden comprises a 3rd generation network and is operated using a main biomass boiler and backup oil boilers. The main boiler needs replacement (so called "re-powering") due to a mismatch between heat load and boiler capacity that has led the boiler operation to become inefficient and has resulted in high network temperatures. Therefore, it is of interest to determine whether or not installing solar at the same time as replacing the boiler could be a cost-effective option compared to simply replacing the boiler. At the same time, seeing that many existing DH systems can keep a boiler functioning longer than the economic lifetime, it is of further interest to see whether or not adding solar heating to an existing system can be cost-effective. Because the cost-competitiveness of solar is highly sensitive to changing economic conditions such as interest rates, studies on competitiveness of solar should also be subject to how cost-effectiveness varies with changing boundary conditions, in order to generalise results. Lastly, adding solar heating to an existing DH system has been seen as one of the obvious use cases to deal with low demand periods such as during summer maintenance, which is why the influence of this on unit heat cost should be investigated. The background outlined in this paragraph forms the premise for the research on existing DH in this thesis.

1.2 Literature review on solar district heating

Paper I provided a full review of SDH, where one section went into the details of SDH integration concepts and treated a case study on a small SDH system. This section provides the most relevant parts to this thesis.

1.2.1 System typologies

There are three parts to consider when including ST into a system:

1. the solar circuit itself (collector, piping, pump, valves and expansion vessel),
2. the integration of the solar circuit into the overall system and
3. the flow control in the solar circuit and the control of the rest of the DH system.

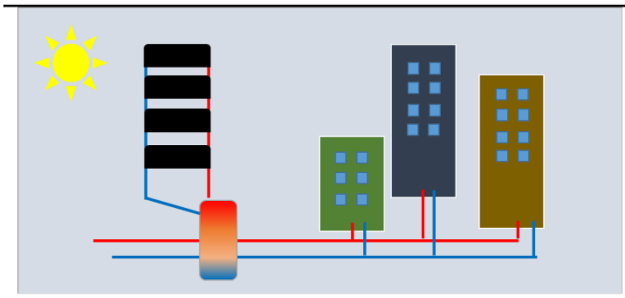
The solar circuit itself can, in principle, have the same design for all types of system typology for DH, but practical details vary depending on whether the collector is ground or roof mounted.

The main differences between typologies are in system integration, and the flow control in the collector circuit is dependent on this system integration. Primarily, two strategies are used in practice: constant, normally high flow rate to maximize solar gain and matched flow, so that the collector field supplies a desired temperature.

If the ST system will only supply a small part of the DH demand, then the system integration is relatively simple, no matter what the system typology is. With very low solar fraction (>50% of summer demand), no storage is needed other than the network itself [21]. With higher solar fractions, storage is required somewhere in the system. The choice is centralised or distributed storage, leading to different system typologies and a need for an overall plan for the whole DH network.

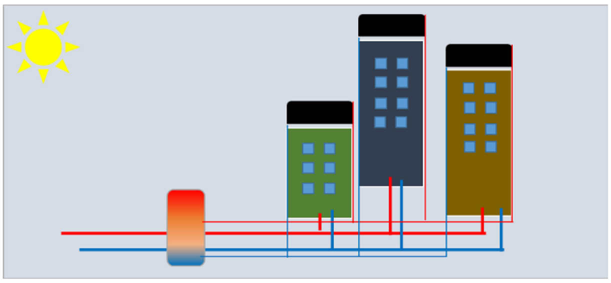
The various types of system typologies in solar district heating (SDH) are shown in Figure 1:

Solar assisted district heating – system typology



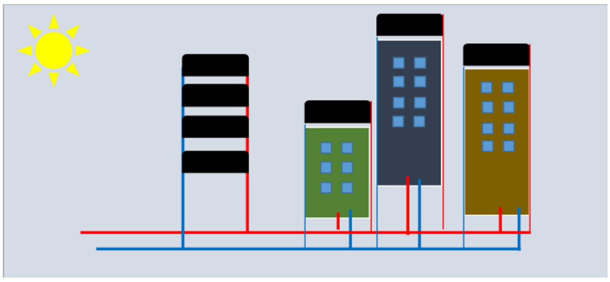
Centralised:

Central storage and central solar collector field.



Centralised:

Central storage and distributed solar collector field.



Decentralised:

Distributed solar collector field(s) without storage (feed-in).

Figure 1: System typologies – overview of the most common system typologies in SDH systems.

In addition to the typologies shown in Figure 1, decentralised systems featuring distributed storage and distributed solar collector fields also exist, but are less common. These can be referred to as semi-decentralised.

In centralised SDH systems, the solar collector field is usually installed close to the main DH plant, which hosts the auxiliary energy system. From a technical point of view, solar heat can be combined with all other fuels for DH, but the auxiliary energy system often relies on natural gas (CHP plants or boilers) or biomass [22–24], and is turned on when solar energy cannot completely cover the heat demand. The solar collector field is usually installed in parallel with the auxiliary energy system. In case of high solar radiation, the collector field often provides the entire temperature rise required by the DH network. If the solar radiation is not sufficient, the auxiliary energy system supplies additional energy to increase the fluid temperature to the DH supply temperature. The boiler central (BC) is equipped with a storage, which can store heat from the auxiliary energy system and the solar collector field. The size of the storage plays an important role in the solar fraction that the system can achieve and short-term storage, normally in the form of steel tank(s), makes it possible to increase the solar fraction of the system up to 15 – 20% [25,26]. Higher solar fractions (up to 90%) are proven to be achievable through a seasonal thermal storage [27]. The storage is charged in summer, when excess solar heat is produced, and discharged whenever it is hotter than the operation temperature of the DH network and the collectors do not produce enough heat.

A ST system that is connected to a DH network outside the main BC is classified as a decentralised system, even when the distance from the feed-in point to the main pumps in the DH system is only some meters [28]. The collector field is normally roof-mounted, but systems with ground-mounted collectors also exist. Nearly all decentralised ST systems are connected to existing DH networks. Unlike centralised system, decentralised plants are often, but not necessarily, located where there is a load and thus an existing DH substation. Decentralised systems are not relevant to this thesis and will therefore not be treated in more detail.

1.2.2 Block heating

Block heating systems are smaller DH systems. Networks supplying residential areas up to 100 single-family house or urban city blocks of up to 400 dwellings can be found [26]. The integration of a ST system into a block heating network can be a cost-effective solution, especially for new low-energy residential areas. This is why nearly all solar block heating systems are built at the same time as the buildings. Solar assisted block heating systems have been built for more than 30 years [29] and research studies have mainly focused on lowering the heat losses, increasing the efficiency and solar fraction of the ST system, while decreasing the costs.

1.2.3 Solar thermal system integration

The solar integration varies with system concept and may consist of different typologies: centralised storage and collector field, centralised storage and distributed collector field or mixed typologies, where there can be both centralised and distributed collector fields and storage.

Normally, systems with diurnal storage have a design solar fraction of around 20%, delivering 80%-100% of the DHW load in the summer months. Higher solar fractions may be achieved using seasonal storages [30], which is generally thought to be reasonable for networks supplying > 100 dwellings [31].

However, one block heating system supplying 52 houses was built in Canada based on energy simulations, employing ST flat plate collectors and seasonal borehole storage in a low-temperature plastic pipe network. The system has reported solar fractions >90% after five years of operation [27]. A similar system of 50 houses was built in Sweden, and although it didn’t achieve the same performance for various operational reasons, it still had an estimated solar fraction around 60% [32]. In both of these systems, individual DHW preparation in combination with roof installed solar collectors on the houses was thought to be the *most* cost-effective solution, which is contrary to earlier studies showing local DHW storage to be the *least* cost-effective solution[9]. The main reason for this is probably that the heating networks are of the low-temperature kind, whereas DHW preparation requires elevated temperatures. The DHW demand is a large part of the total heating demand in low-energy housing and that may favour local DHW preparation with local storages supplied by solar thermal in combination with an electrical heating element for peak demand.

Increasing the solar fraction for systems with smaller storage units has been proved successful in some Swedish systems supplying low-energy housing by employing central DHW preparation in a so called GRUDIS distribution system [33]. These systems represent a low-temperature alternative to networks with local DHW preparation, in that they avoid deployment of comprehensive house substations that allow for DHW-preparation, while keeping the benefits related to lower operating temperatures. This type of system is used in Vallda Heberg, which is used as a case study and acts as the basis for the study in **Paper II**.

1.2.4 GRUDIS

The acronym GRUDIS is short for the Swedish term GRUppcentralDIstributionsSsystem. The GRUDIS system was developed during the 1980s with the intention to offer a low-cost distribution alternative to residential areas where traditional steel pipe culverts would be too expensive due to low network heat demand densities. Despite the long history of GRUDIS, it is treated as a 4th generation DH technology in this thesis due to the fact that the technology was developed as an alternative to the 3rd generation DH system technology and that the characteristics largely correspond to those considered desirable in future DH systems [13,14].

Main characteristics of the GRUDIS technology:

- Plastic pipe (PEX) culvert.
- DHW employed as heat carrier and drawn off directly from the pipe without hydraulic separation.

Fundamental properties of GRUDIS (and plastic pipe systems in general):

- Simple and flexible installation.
- Long pipes (up to 200 m), meaning no splices.
- No welding works.
- Limitations in working temperatures and pressures.

The technology received a great deal of attention from construction companies and property entrepreneurs, but was largely disregarded by the district heating sector. In addition to restrictions in applicable working temperatures and pressures, limited availability of larger pipe sizes (> DN80) led the distribution concept to be considered suitable primarily for isolated heating networks in smaller residential areas or villages.

Despite this, based on a range of operational evaluations and years of system experiences, the Swedish district heating association has concluded that the GRUDIS technology may indeed be suitable when used in a secondary network, adjunct to a primary network with higher temperatures and pressures [34]. This was the basis for the hybrid distribution system of Vallda Heberg, which is described in the *section 2.1.1.*

1.3 Research objectives

The research presented in this thesis was initiated as a part of a larger European project called SolNet-SHINE which focussed on integration of solar heat in heating networks and, therefore attempts to make the results quite general, although simulations are based on Nordic climatic and economic conditions.

1.3.1 Objectives - new built systems

The research presented in relation to new DH aims to investigate how the energetic performance of a newly built solar assisted district heating system may be improved by changing the distribution concept altogether. The first objective is to perform a review of various methods of solar energy system integration (Paper I) to identify a promising solution for DH in low-density networks. A hybrid distribution concept is found and this is comprised of a combination of 3rd and 4th generation DH technology and is compared to a 4th generation (*Paper II*) and 3rd generation distribution concept (*Paper II*), in an attempt to determine the most suitable concept for new DH systems. The main focus of this comparison is on the boiler supplied energy, solar fraction and overall system performance.

A secondary objective is to evaluate the heat loss range (and thereby resource efficiency) by employment of the different district heating concepts. This is done both by variation of the line heat density (*Paper II),* aiming to reveal any range bound limitations related to employment of the concepts (*Paper II*) and, by variation of pipes with different insulation type and thickness (*Paper III*). These methodological variations enable well founded conclusions in regard to the secondary objective and enables investigation of the third objective.

The third objective regards the cost implications of using various technologies, as economic conditions are of major significance for their employment. Unverified information from industry representatives is used, aiming to identify potential cost benefits of using 4th generation DH technology (*Paper II*). This is used to motivate an extended scope of technology comparison of 3rd and 4th generation DH technology as well as a combination of the two and yet more detailed costs (Paper II). Using this information, a detailed economic study is made with verified cost information from industry, with the aim to reveal the technological solution with the lowest life cycle costs under varying economic conditions (*Paper III*).

1.3.2 Objectives - existing systems

The research presented in relation to existing DH primarily aims to investigate whether or not adding solar thermal to an existing DH system can be cost-effective compared to a business-as-usual scenario using a boiler with or without storage (*Paper IV*). A secondary objective is to see whether or not adding solar thermal is cost-effective when done together with a boiler replacement with or without storage. A boiler central is modelled with different solar array sizes and thermal storage volumes, before the energetic performance is simulated using a measured load profile from a real DH system along with measured climate data for one year. The results are used together with collected cost data for the boiler, fuel and solar thermal system to derive the unit cost of heat, for both the (perhaps most common) case where solar thermal is added without installing a new boiler (so-called “retro-fit”) and where it is added at the same time as a boiler replacement (so-called “re-powering”).

A third objective treats the cost-competitiveness of using ETCs instead of FPCs, for an equally size collector field, in the same scenarios.

A fourth objective is related to the cost-competitiveness of solar in these scenarios for changing economic boundaries conditions, when:

- Collector cost is static and interest/fuel cost increase.
- Collector/fuel cost is variable and unit heat cost is equal between solar and non-solar.

The fifth and last objective looks into how installing solar thermal together with a boiler replacement, can affect unit heat costs due to reduction in backup-boiler fuel use during summer maintenance of the main boiler.

An additional sixth objective was added for the sake of this thesis, where the impact of lower return temperatures on the techno-economic performance of the solar heating system was investigated.

1.4 Delimitations

1.4.1 Delimitations – new built systems

The primary focus of the technical analysis conducted in the papers on new DH included in this thesis is on the heat losses of the pipe network and distribution units in various distribution systems, and how this affects the solar contribution. The solar collector type, size and orientation (tilt/azimuth) was not varied.

Pressure considerations are not taken into account when modelling, although they are considered indirectly during the sizing of the pipe network. In the pipe network, bends and tees are not included in Paper II, neither are valves and other balancing components. As such, the results presented are supposed to be taken as indicative, rather than definite. Nevertheless, despite the potential heat losses (and costs) of the omitted hydraulic parts, it is assumed that the impact of neglecting them is more or less the same for all three distribution systems and that the difference in results therefore is representable for the real differences.

However, results from paper III are based on detailed costs for all necessary components including labour and are therefore more accurate, although the accuracy is still slightly uncertain due to mainly labour estimates being uncertain by nature. Furthermore, the heat losses of the bends and tees and so on are omitted also in Paper III, so the resulting energy balance is indicative rather than definite, although the omission of losses is assumed to impact the results similarly for all simulation variants.

1.4.2 Delimitations – existing systems

The primary focus of the analysis in *Paper IV*, is on the lowest unit heat cost for DH system variants with or without solar thermal collectors and storage. Both flat plate collectors (FPCs) and evacuated tube collectors (ETCs) are included in the study, although the latter is only investigated for one array size, due to uncertainty in cost data and limited availability of information on such collectors for large scale applications. The results regarding the suitability and cost-competitiveness of ETCs for DH applications are therefore somewhat uncertain. As for the papers on new DH, the collector orientation (tilt/azimuth) was not varied.

Furthermore, the load profile and climatic data is for one year only and, despite the similarity between the climatic data of this year and an average year, the variation in climate from year to year may have significant impact on cost-competitiveness and therefore the results should be interpreted as indicative, rather than definite.

The economic boundary conditions, i.e. costs for components such as solar collectors, storage tanks and so on, are by nature uncertain, although based on well reputed sources. The unit heat costs presented are therefore inherently imprecise and the results are indicative for the differences between system configurations, rather that definite in the sense that they represent absolute values. The results for existing DH therefore include results in the form of sensitivity studies that allow for deduction of competitiveness of solar versus non-solar system configurations when economic boundary conditions change.

2. Method

Table 1 provides a summary of the research evolution for the papers presented in this thesis, which objectives the papers address and which methods were employed to answer the research aims. The purpose of the table is to enable a wholistic view of the research progress and logic behind the methods applied. The methods are largely treated throughout the current chapter.

Table 1: Overview of research evolution for papers in this thesis with description of main subject, motivation for the study and method applied. Abbreviations: Boiler central (BC), Energy balance (EB), line heat density (LD), life cycle cost (LCC) and levelised cost of heat (LCOH).

Paper	Objective	Description	Motivation	Method
I	1.1	ST integration best practice.	Increase use of ST in DH, save boiler fuel.	Literature review.
II	1.2/1.3	Improvement of SDH system efficiency at potential lower cost.	Demonstrate viability of novel distribution vs. 2 Alternatives.	TRNSYS general model, EB wrt. LD, simple cost calculation.
III	1.2/1.3	Precise quantification of SDH economics.	Demonstrate cost advantage of novel distribution.	TRNSYS general model, EB wrt. Pipe type/insulation level, detailed cost calculation *Wikells* (LCC).
IV	2.1 – 2.5	Determination of economic boundaries for use of ST in DH.	Demonstrate cost advantage of ST for existing DH systems.	TRNSYS BC model, EB, LCOH wrt. Interest rate and fuel cost.
Thesis	2.6	Impact of lower return temperatures on ST performance.	Demonstrate benefits of operational measures on ST system.	TRNSYS BC model, EB, LCOH with reference costs.

Table 1 refers to the following tools used for district heating system simulations and cost calculations:

- TRNSYS [35] is a dynamic simulation program for energy systems that offers a high level of detail in modelling, allowing users to create system models by combining components from various libraries, with a mathematical foundation for each component provided in a mathematical reference. It is known for its ability to solve systems of equations with a large set of independent variables through iterative calculations, using a user-specified convergence tolerance and time step.
- Wikells [36] is used estimate costs and create quotes for building services. It allows for customization based on specific costs within a company and is widely used in the HVAC consulting sector due to its history and availability of modules for building, electrical, and HVAC works. Users can select standard components or add custom ones for projects, adjusting man hours and cost information for each component. Once the project specification is complete, they can generate reports and cost specification sheets for sharing.

Other software tools utilised:

- DHWcalc [37] is a software developed for calculating Domestic Hot Water consumption based on statistical distribution in residential areas, currently in its second generation. The software interface includes input boxes for parameters related to DHW draw-offs, tap categories, seasonal variations, and holiday periods. Users can specify household types (single or multi-family) and daily water consumption to generate diverse DHW profiles with variations in daily draw-offs.

2.1 District heating systems

This subchapter provides case descriptions for the district heating systems used as basis for the system models made in the articles comprising this thesis.

2.1.1 Vallda Heberg - new built system

The Vallda Heberg area, built by the housing company Eksta in Sweden, consists of 26 single-family buildings, four multifamily buildings (4 apartments per building), 6 terrace houses with in total 22 dwellings and also a nursing home for elderly people with 64 apartments (see Figure 2). The total heated floor area is about 14000 m^2 and the estimated yearly heat demand is 621 MWh [38], although measurements have shown demands of 722 MWh [39]. All buildings are designed as passive houses with mechanical ventilation heat recovery, and thus the heat demand is low. In the houses, heat is supplied by floor heating in the bathrooms and an additional water/air heat exchanger in the supply air to the building.

Figure 2 shows a schematic of the Vallda Heberg district heating system with colour coded distribution pipelines and intermediate substations (SS) connected to roof-integrated collector areas:

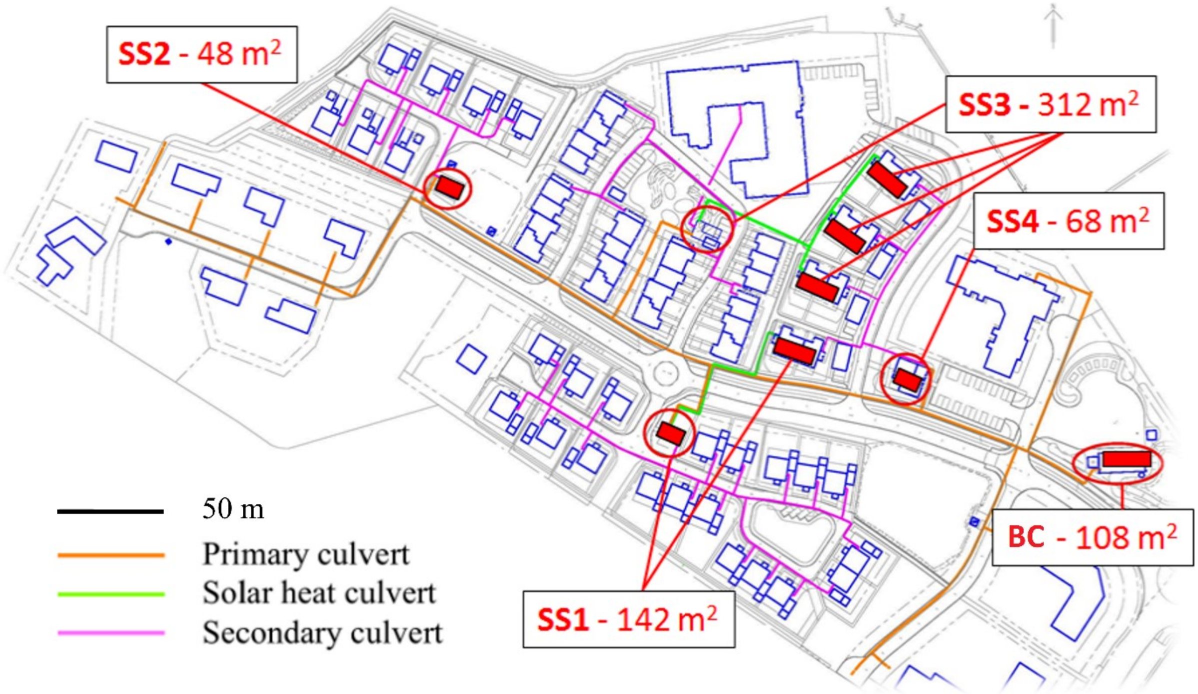


Figure 2: Schematic of the Vallda Heberg district heating system with denoted intermediate substations (SS) and the respective roof-integrated collector areas connected to these, together with colour coded distribution pipelines.

The local DH system comprises a BC with a 300 kW wood pellet boiler, supplying four intermediate substations through a steel pipe primary culvert (PC). Each intermediate substation is connected to its own collector array (see Figure 7) and supplies a housing area through a secondary culvert (SC), comprised of cross-linked polyethylene (PEX) pipes insulated by evacuated polystyrene (EPS). In the BC and in each intermediate substation there are buffer storage tanks. There are 108 m^2 evacuated tube solar collectors on the BC and 570 m^2 flat plate roof-integrated solar collectors in connection to the substations. The distribution network from the four intermediate substations to the dwellings are of GRUDIS type [34], which essentially is a DHW circulation loop with direct connection to the houses.

The DHW is prepared in the intermediate substation by preheating incoming cold water in the buffer storage tank when solar heat is available and providing auxiliary heating with the PC, when needed. The floor heating in the houses is a part of the DHW circulation loop and to avoid risk of legionella, the entire loop is maintained between 50 °C and 60 °C. For this reason, there is no flow control in the floor heating loop. This results in a very simple and cost-effective heating system, as well as a simple distribution network with plastic pipes. However, as the buildings are passive houses, the energy density of the network is low, which means that the distribution heat losses are a large part of the overall energy use in the system (see Figure 3).

Figure 3 shows the monthly energy balance in a typical meteorological year (TMY) for the Vallda Heberg system as simulated in *Paper II*. Percent values show relative shares of the energy turnover in energy supply/demand.

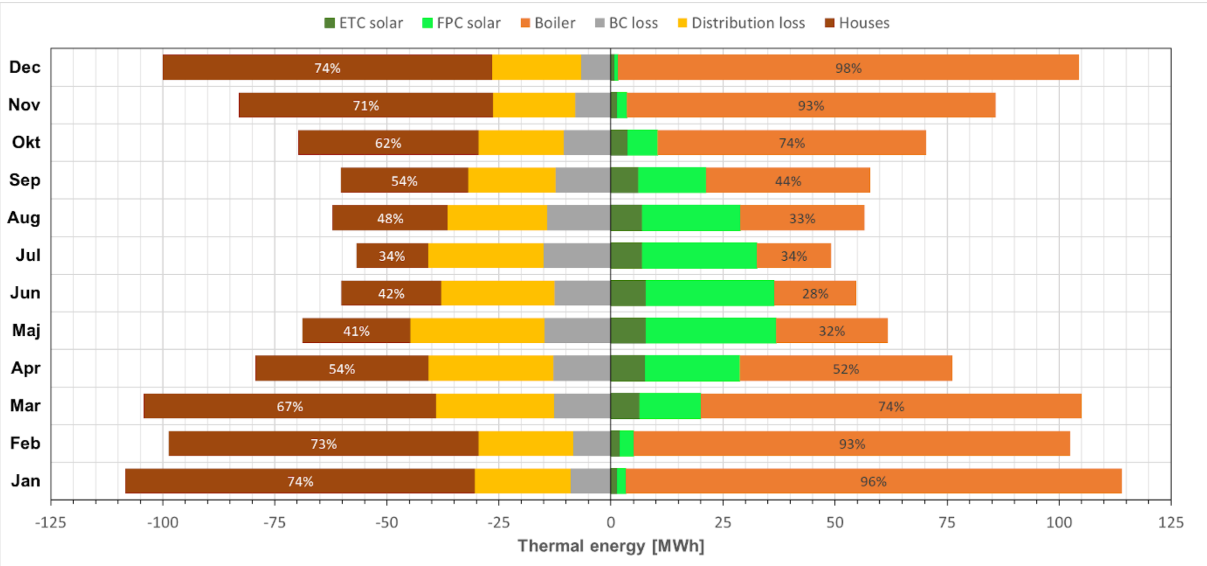


Figure 3: Monthly energy balance in 2015 for the Vallda Heberg district heating system as simulated in Paper II. Percent values show relative share of energy supply/demand.

2.1.2 Hemse - existing system

The Hemse DH system is located on the island of Gotland, Sweden. It has an annual heat demand of about 11.5 GWh, supplied by a 7 MW biomass main boiler and two 4 MW oil backup-boilers, whereby one acts as a reserve. The design heat load of the DH system was 4 MW and, due to planned future loads in the network being discarded, the boiler ended up too big for the present system. This has led to high supply/return temperatures, which could be lowered by installation of a smaller boiler. The owner, Gotland Energi AB (GEAB) would like to replace the boiler with a new boiler of different (lower) capacity – commonly termed “re-powering”.

Figure 4 shows the annual load profile for year 2015 in the Hemse DH system, along with simulated values for supply and return temperatures used in *Paper IV*. The load varies between 0.5 MW in summer to 3.0 MW in the winter, with corresponding supply temperatures from 85°C in winter (-10°C and lower) to 65°C in summer (16°C and higher). The return temperatures will vary according to heat demand, but for the year in question were between 43°C and 61°C, with the highest values in summer.

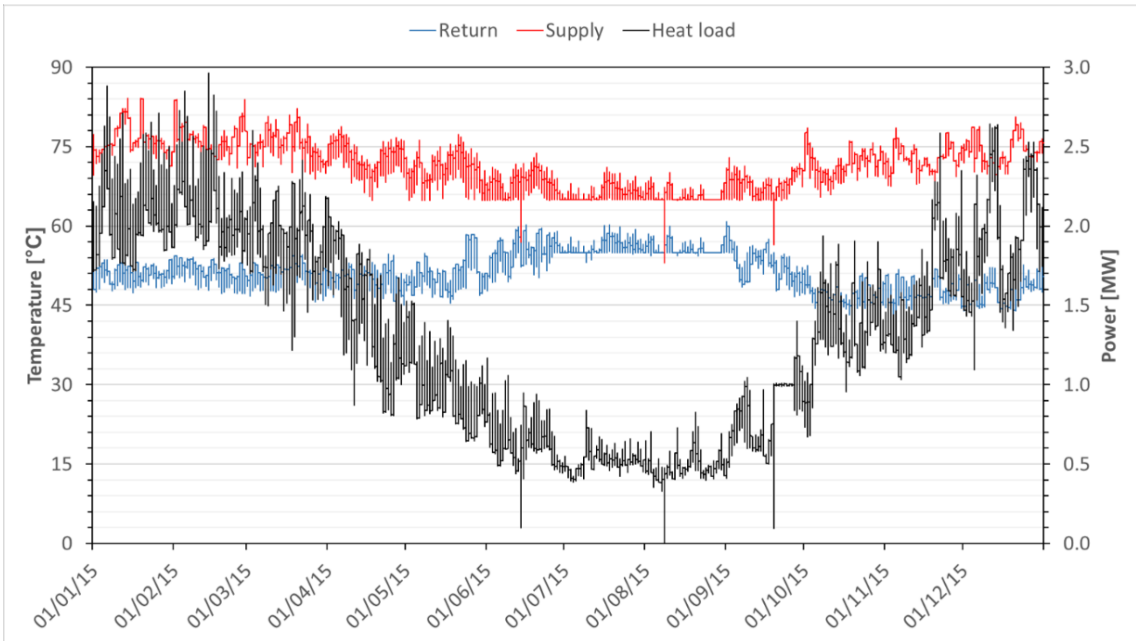


Figure 4: Annual load – Load profile for the Hemse DH system in the year 2015.

In conjunction with the replacement, it could be interesting to install a solar heating system, both for the sake of reducing heat costs and/or backup-boiler fuel use.

Figure 5 shows a satellite image of the Hemse boiler plant (yellow square) and surroundings. There is about 10000 m^2 of available land (red triangle) for installation of about 3000 m^2 of solar collectors [40]. However, the shown land area could be expanded eastwards and westwards to give triple the available land and, hence collector area.

Figure 5: Boiler central – Satellite image of the Hemse boiler plant (Yellow square) and surroundings. The northern area (red triangle) shows available land for installation of solar collectors.

2.2 System model development

In Paper II, a generalised system model was made based on the Vallda Heberg residential area, using a systematic method to first size and then model the piping networks and using manufacturer catalogue data for calibration of pipe heat losses.

Three system models were made: Hybrid, All GRUDIS and conventional DH and these are described in *Ch. 2.1.1*

Computer models were constructed for three different distribution concepts in order to devise a research setup that would allow for general results, enabling a just comparison. The residential area was assumed as consisting of only single-family houses and supplied by identical intermediate substations. The approach used for sizing the piping network was to systematically calculate the size based on loads in the system.

By using established standards and guidelines to size the network distribution pipes, before calibrating the specific pipe heat losses toward manufacturer catalogue values, any uncertainties imposed by measurement data could be ruled out. The logic behind this choice of approach was that, despite potential lack of correspondence between simulation results and real system performance, the relative differences between the performances of various distribution concepts would be representative of those that could be found in reality.

Paper III used the same system model, but changed out and extended the scope of pipes modelled and therefore required additional calibrations of the pipe model to include other pipe types.

Two system models were used: Hybrid and All GRUDIS, with the same model descriptions as in *Paper II*.

Paper IV made use of a boiler central model based on the that in the generalised model, though with more detailed control of the boiler, in addition to a different storage tank setup for those model variations where this was included.

2.3 System and model description

The system and model description has been divided into several sections, where *section 2.3.1* contains descriptions of the distribution systems and pipes, *section 2.3.2* provides information about models used solely to study new DH, while *section* 2.3.3 provides a description of the model used to study existing DH. Lastly, *section 2.3.4* - *2.3.6* describe common inputs, models and processes for both the papers on new and existing DH.

Figure 6 shows a schematic interpretation of the Vallda Heberg system as it has been modelled in *Paper II and III*. The system has been simplified from the original (see Figure 2) and made symmetric in order to simplify the modelling and make the effect of studied parameters easier to deduce from results. Similar schematics are available in the cited papers for the alternative distribution systems described in *section 2.1.1*.

It is worth noting that for the hybrid system shown in Figure 6, the conventional and GRUDIS distribution is referred to as primary culvert (PC) and secondary culvert (SC), respectively. This wording is used in other sections of the thesis as well when referring to parts of the system of a particular pressure class and temperature level associated with said distribution concepts.

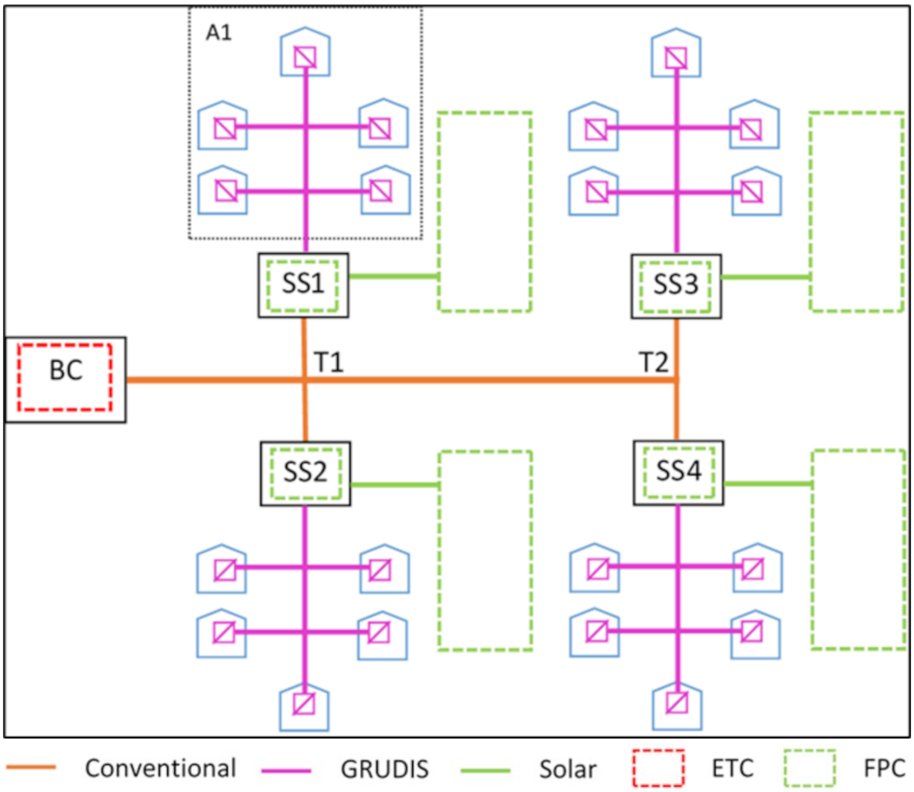


Figure 6: System layout - schematics of hybrid network as it has been modelled in *Paper II and III*. Evacuated tube collectors (ETC) are located on the boiler central (BC) and flat plate collectors (FPC) are located on either intermediate substation (SS) and/or ground.

2.3.1 Distribution systems

Table 2 shows an overview of the distribution network characteristics for the different distribution concepts investigated in relation to new DH (*Paper II – III*). These concepts are described more closely in *section 2.3.3.*

Paper II focused on the small district heating system of the Vallda Heberg residential area, which employed a hybrid distribution concept comprised of high-temperature, steel pipe distribution as customary in the 3rd generation DH and low-temperature, plastic pipe distribution as envisioned in the 4th generation DH. The paper further evaluated the use of an alternative distribution concept named All GRUDIS, which featured the use of only low-temperature, plastic pipe distribution and compared this to a conventional distribution concept, consisting of only high temperature, steel pipe distribution. With a wide scope, it was possible to provide a comparison of both historic, novel present and possible future DH technology performance.

Paper III went on to investigate the detailed economic performance of two of the distribution concepts presented in **Paper II**, omitting the conventional DH system alternative.

Paper IV features no distribution system for heat, as the study is focused on the heat supply only. However the solar distribution pipes employed in this study was significantly different for the variant modelled with evacuated tube collectors, so this is described in this sub-chapter.

Table 2: Distribution network characteristics – Overview of the pipe type and application area, as well as design operating temperatures for the distribution systems used in Paper II and III.

	GRUDIS	Conventional DH	Hybrid
Primary network	PEX main/branch/service pipes Temperature supply/return 60/50 °C	Steel main/branch/service pipes Temperature supply/return 75/45 °C	Steel main/branch pipes
			Temperature supply/return 75/50 °C
Secondary network	N/A	N/A	PEX branch/service pipes
			Temperature supply/return 60/50 °C
Solar culverts	Steel main/branch pipe(s)	Steel main/branch pipe(s)	Steel branch pipes
	Copper header/connection pipes	Copper header/connection pipes	Copper header/connection pipes

2.3.1.1 Hybrid distribution system (Vallda Heberg)

Figure 7 shows a schematic illustration of the hybrid heat distribution system at Vallda Heberg, with the boiler central (BC) to the right, substation in the middle and a passive single-family house to the left. Hot tap water is prepared by supply of cold water to the substation, where it is heated and distributed through the secondary culvert to the load.

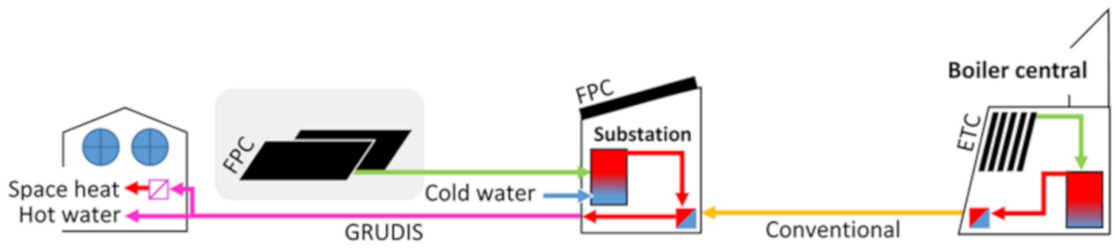


Figure 7: Hybrid distribution - Simple schematic of the hybrid heat distribution concept with boiler central (BC), intermediate substation and single-family house. Roof and ground mounted flat plate collectors (FPC), evacuated tube collectors (ETC) on BC.

2.3.1.2 Alternative distribution systems

Two alternative system designs have been investigated in the papers comprising this thesis:

1. **All GRUDIS:** EPSPEX culvert and central DHW preparation in boiler central.
2. **Conventional DH:** Pre-insulated steel-pipe distribution and local DHW preparation.

The main similarity between these two system designs is the lack of intermediate substations. This involves a modified BC and extra steel distribution pipes between FPC installation location and the BC (see section 2.3.1.3 for more information on the solar culvert pipes). Both system designs feature a similar configuration in that solar heat is harvested on rooftops of buildings attached to the network and stored in buffer storage units in the central BC (see Figure 8). The BC thus includes one buffer storage for the boiler in combination with evacuated tube collectors (ETC) and one buffer storage for the flat-plate collectors (FPC). The main differences are the distribution pipes (steel- vs. plastic pipes) and the location of the DHW preparation.

Figure 8 shows a schematic of a centralised solar district heating system using the All GRUDIS concept, where cold water enters the boiler central and is heated and distributed through the secondary culvert to the load as DHW. The buffer storage in the boiler central provides (pre-) heating of the cold water and the DHW-circulation flow in the culvert, with additional heat provided by the boiler and ETC buffer storage, when needed.

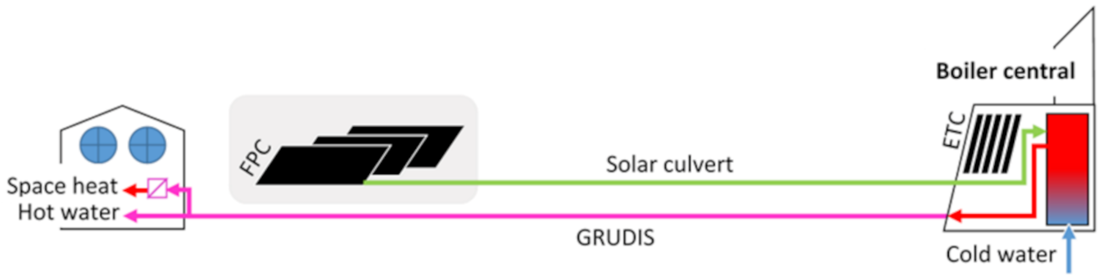


Figure 8: GRUDIS distribution - Simple schematic of GRUDIS distribution system with boiler central (BC) and single-family house. Ground mounted flat-plate collectors (FPC) and evacuated tube collectors (ETC) on the BC.

Figure 9 shows a schematic centralised solar district heating system using the conventional DH concept, where cold water enters the house substation. In the conventional DH system, the DHW is prepared in the house substation, and so the buffer storage in the BC is used for preheating the water in the culvert, with additional heat provided by the boiler and ETC buffer storage, when needed.

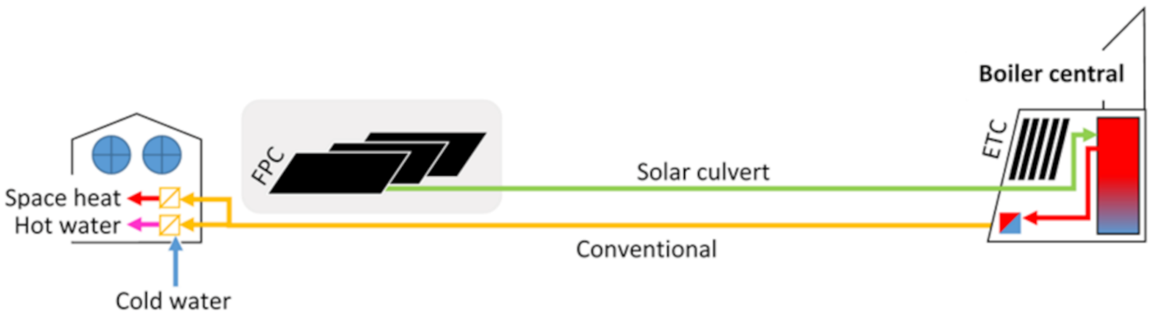


Figure 9: Conventional distribution - Simple schematic of conventional DH distribution system with boiler central (BC) and single-family house. Ground mounted flat-plate collectors (FPC) and evacuated tube collectors (ETC) on the BC.

2.3.1.3 Solar distribution pipes

The solar heating system is modelled in the same way in all system models, both for new (Paper II and III) and existing systems (Paper IV). The solar collector pipes and the header pipes (in ground) are modelled as copper pipes, whereas the distribution pipe between the collector arrays and the storage location are modelled as twin steel pipes.

The solar culvert layout depends on the applied solar collector type due to the pressure limitations of respective collector type. Despite the possibility of having similar pressure ratings for different collector types, which enables operation under the same pressure regime, the pressure-drop over a large scale FPC can be significantly lower than over an ETC counterpart. This entails geometric limitations on the solar collector rows, as one row of series connected FPCs can be much longer than that comprised of ETCs. Thus, for the same total row length in a system, the number of arrays will be higher in an ETC system than in an FPC system, which has implications for both the required pipe length and pipe size used for the installation (Figure 10).

Figure 10 shows a schematic overview of the principal differences in distribution pipe layout when employing FPCs (left) or ETCs (right) in a solar heating system. As can be seen, using ETCs leads to a need for both larger pipes in order to reduce the impact of higher collector pressure loss on the total pressure loss, but also requires significantly more pipes to accommodate the higher number of arrays. Only *Paper IV* actually employs large scale ETCs and have results impacted by the differences between pipe layout, although the pipe layout depicted for FPCs has been assumed for the pipe sizing and calculation of pipe costs in *Paper II* and *Paper III*.

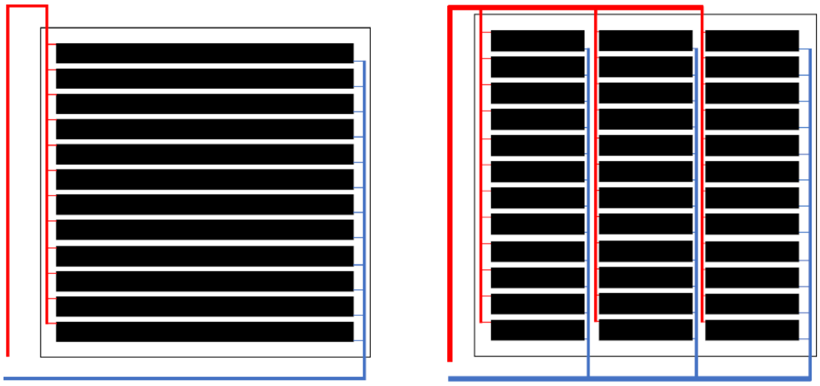


Figure 10: Culvert differences – Schematic overview of the distribution pipe layout for a solar heating system using large scale flat plate collectors (left) and evacuated tube collectors (right).

2.3.2 New district heating model

This section describes the different system models for the distribution systems outlined in *section 2.3.1*. All three models were part of *Paper II*, while only the hybrid and All GRUDIS model were included in *Paper III*.

2.3.2.1 Hybrid system model

All system models developed in **Paper II** build on the same overall approach (see Figure 11), although the hybrid system approach is the only one displayed here. The primary reason for using this simplified approach is due to limitations on the maximum number of component outputs in TRNSYS and long simulation times when exceeding this maximum. The simplified model used required altering the maximum number of outputs possible and the long simulation time obtained resulted deterred from creating a more detailed model where the output number would have to be increased further. Due to the symmetric nature of this theoretical DH network, however, this simplified modelling approach is assumed to have minor influence on the results, as the primary focus of this study is total energy use and an inter-comparison between system variants.

Overall modelling approach

The hybrid system has been modelled by the use of three subsystem models in TRNSYS:

1) Building and house substation model (SH load multiplied by 25 to represent one housing area).
2) Intermediate substation model (multiplied by 2 to represent sub-system load) with ST system.
3) Boiler central model.

The end result of this approach was that the load as seen from the BC was based on scaling house model by 25 and intermediate substation model by 2 to represent a total load of 100 houses. The employed DHW load in the SS was based on two housing areas (50 houses) and divided by two to model the appropriate load (coincidence factor – *see section 2.3.6 for more information*).

Figure 11 shows the overall model structure of the hybrid system model including the subsystem models:

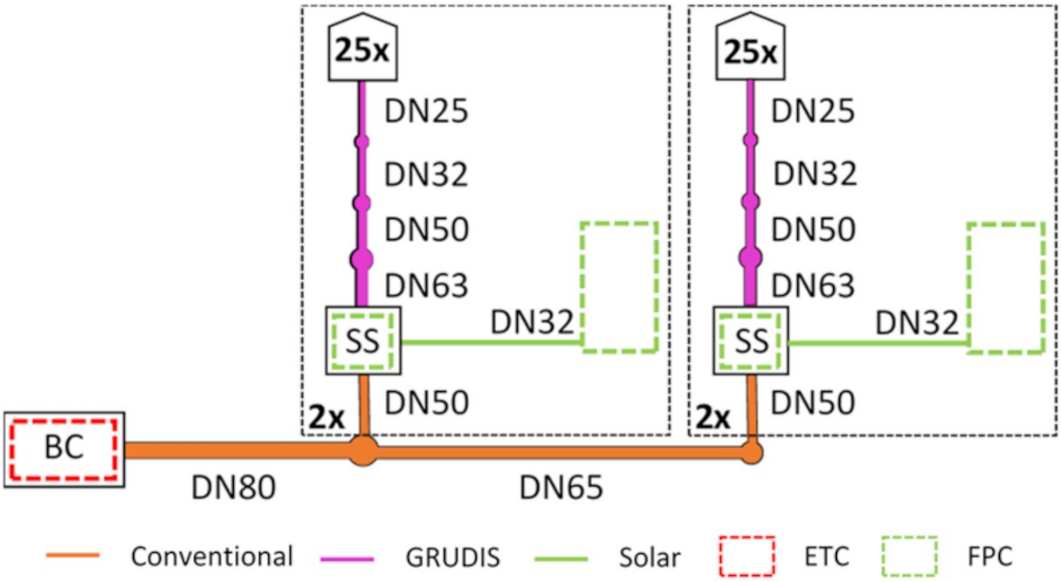


Figure 11: Generalised approach – Schematic showing the hybrid system simulation model and applied pipe sizes employed in *Paper II and III*. Copper pipes in solar thermal system are not shown. Scaling factors (2x and 25x) are shown in the substation models where these are used [12]. BC = Boiler central. SS = substation.

Intermediate substation model

The intermediate substation model was based on substation 1 in the Vallda Heberg DH system (*see section 2.1.1*) and was modelled as consisting of a solar buffer storage, circulation pumps and internal piping, in addition to a solar loop comprised of two solar collector arrays supplied by a solar culvert and collector connection pipes.

The model featured large grouped solar arrays to represent the total collector area (see Figure 7), in addition to using a realistic pipe model (*see section 2.3.4*), which was thought to yield trustworthy results.

Lumped pipe segments

Pipes were lumped together to simplify modelling.

Papers II and III (referring to Figure 11)**:**

- Overall system modelled using BC model with PC pipes connected in series to supply branch pipes for intermediate substations (SS). SC pipes connected in series to house model.
- Each housing area had one segment for the solar culvert connected between intermediate SS and ground-mounted collectors, forming part of the system model.

The model shown in Figure 11 is only valid for the Hybrid concept. The other two concepts are modelled similarly, except there were now intermediate SS and so the solar culverts ran all the way to the BC (see Figure 8/Figure 9). Furthermore, in terms of pipes sizes, the subsystem with “GRUDIS” pipes in Figure

11 are of a larger pipe dimension than in a conventional DH system model. Conversely, the subsystem with "conventional" pipes are of a smaller pipe dimension than in a GRUDIS DH system model.

Load as seen from the BC was based on scaling house model by 25 and intermediate substation model by 2 to represent a total load of 100 houses. Pipes were dimensioned by calculating the required flow rates to cover the network load in different parts of the network at the design operating temperatures.

2.3.2.2 All GRUDIS model

In order to follow the outlined modelling approach here, the reader is referred to the respective papers. The description aims to describe how the differences in the model compared to the Hybrid model explained in *section 2.3.2.1.*

Papers II & III:

- The All GRUDIS model integrated the intermediate substation into the boiler central, omitting hydraulic separation. Primary culvert pipe segments connected directly to the BC (see Figure 2a in *Paper III* for schematic) and scaling house loads by 50 instead of 25, due to lack of intermediate SS (as in Figure 11). DHW profiles and buffer storage were thus modelled in full size (*see section 2.3.6*).
- Solar collectors were aggregated into two ground mounted arrays, one representing the collector area installed on the substation roof system and one representing the ground mounted array, in the hybrid system model (see Figure 11). These two arrays were connected directly to the BC's buffer storage (see Figure 2a in *Paper III* and Figure 8 in thesis, for schematic), representing the majority of collector area and former substation attached collector area, respectively.
- Due to the aggregation of solar collectors, solar distribution pipes resembled the Hybrid model but had larger dimensions to accommodate flow rates and pressure losses. Solar culverts included three twin-pipe segments: two branch pipes for arrays and one main pipe connecting them to the BCP, with lengths determined by array locations near the boiler central.

2.3.2.3 Conventional DH model

In order to follow the outlined modelling approach here, the reader is referred to the respective papers. The description aims to describe how the differences in the model compared to the Hybrid model explained in *section 2.3.2.1.* The conventional system layout resembles that for GRUDIS in Paper II.

In Paper II, the conventional DH system was modelled:

- Solar Buffer Store: Used only for preheating return flow in the culvert; DHW was prepared in house substations via dedicated heat exchangers.
- The DHW profiles scaled down draw-off volumes by a factor of 50 (modelled houses) and used as input to house model (*see section 2.3.6*).. House model load scaled by 50 in each junction to arrive at total load.
- Floor Heating System: Connected to the SH loop via the SH heat exchanger, differing from the hybrid and All GRUDIS systems where it was tied to the DHW circulation return (explained in *Paper V*, which is not included in the thesis). The pump ran with a fixed flow rate to preserve passive heating and ease comparisons between systems.
- Distribution Pipes: Modelled as twin-steel pipes instead of PEX pipes. Segments matched those of the Hybrid system for main and branch pipes (see Figure 11), but service pipe dimensions were smaller due to lower flow rates. Solar culvert modelling remained unchanged.

2.3.2.4 Common subsystem models

In all system models developed for the new build systems, there is a set of common subsystem models employed:

Building and house substation model, comprised of a two-zone building model based on real drawings of the house. One zone is heated by a mechanical ventilation system with auxiliary water-air heat exchanger and heat recovery, while the other zone uses floor heating. The model takes into account air infiltration, shading and windows.

Boiler central model, including the boiler, evacuated tube solar collectors and buffer storage connected to a heat exchanger that supplies the DH network. Internal connection pipes are included to account for heat losses. The boiler is controlled to maintain a part of the buffer storage hot at all times, during the summer maximising solar heat and during the winter solar preheating. The boiler efficiency is modelled by an equation to realistically model boiler fuel use.

2.3.3 Existing district heating model

Figure 12 illustrates a simplified model of a district heating system with three main variants as investigated in **Paper IV**. For the solar assisted system (B + ST + SC) variant, additional sub-variants exist as part of a parametric study (see *section 2.4.2*). The greyed-out part represents components outside the system boundary in this study and for simplicity, the solar collectors are simulated as one large field while pipes are lumped so that one pipe element represents the entire length of a particular pipe type.

A description of the heat supply configuration of these variants is presented in Table 3.

Table 3: Main variants – overview of the heat supply configuration in main variants simulated in *Paper IV*.

Parameters	Boiler-only	Boiler + storage	Boiler + storage + solar
Boiler	3.0 MW	2.5 MW	2.5 MW
Storage	NA	100 m^3 (V_{boil})	100 m^3 (V_{boil}) + 0.1 m^3/m^2 (V_{sol})
Collector Area	NA	NA	500 – 10000 m^2
Tilt/azimuth	NA	NA	40°/0°

The storage in the system is divided into a boiler part (V_{boil}) of 100 m^3 charged by a wood-pellet boiler and a solar part (V_{sol}) of 0.1 m^3/m^2 collector area, charged by a solar collector field. This is done to prioritize the solar heating system and ensure high collector efficiency by maintaining the lowest possible return flow temperature to collectors. The storage discharges continuously through a heat exchanger, with the boiler keeping V_{boil} warm during winter and the solar heat being used for preheating. In summer, solar energy heats the entire storage using a simple stratification aid to regulate the flow in the storage based on the collector temperature and is supplemented by the boiler when needed.

Note that boiler outlet temperature remains constant throughout the year, while the supply temperature from the BC to the load changes based on the season according to ambient temperature - ranging from 85°C in winter (ambient temperature of − 10°C and lower) to 65°C in summer (ambient temperature 16°C and higher). This differs from the models used for new DH in the thesis. Aside from this, the model is similar in that the boiler efficiency is modelled by an equation to realistically model boiler fuel use.

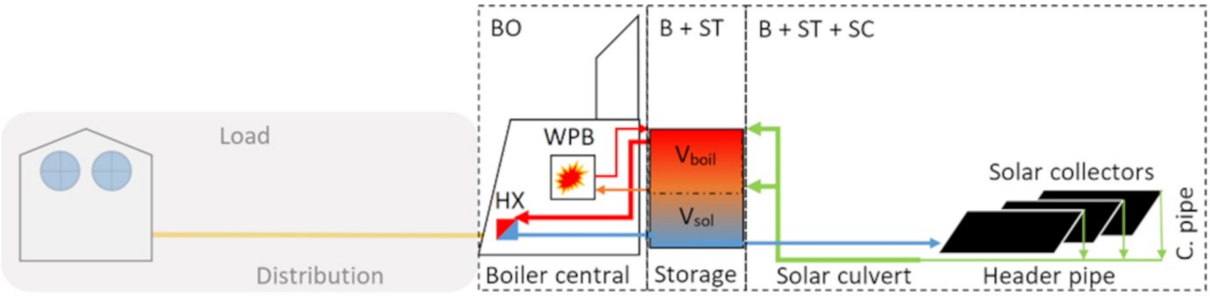


Figure 12: Solar assisted model – Schematic showing the simulation model of the district heating system variations with solar collectors. Abbreviations: Boiler-only (BO), Boiler + storage (B + ST), B + ST + Solar collectors (B + ST + SC), Connection pipe (C. pipe), Wood-pellet boiler (WPB), Heat exchanger (HX).

2.3.4 Distribution pipe model

The distribution pipe model is a buried horizontal single or twin-pipe system, specified by pipe/trench dimensions and thermal conductivity parameters. Layers are concentric, implying a circular trench.

Papers II & III:

- Steel pipes modelled as standard pre-insulated pipes, replacing trench gap thermal resistance with PE casing thermal resistance in due to model limitations.
- EPSPEX pipes treated as having combined EPS insulation and casing (no separate casing thermal resistance, trench gap thermal resistance included).
- Pre-insulated PEX pipes followed the same method as steel pipes.

Pipe types were combined into segments to reduce simulation complexity, with segment lengths matching the total length of constituent pipes.

The solar pipes in Papers II–IV were modelled as pre-insulated steel pipes for the solar culvert, while headers and connection pipes used pre-insulated single pipe ducts. Only connection pipes were above ground.

2.3.5 Model calibration

The model calibration is summarised here for the respective papers. Parts not mentioned here have not been calibrated.

Paper II/III:

- **Pipe Heat Loss**: Calibrated by simulating and comparing specific heat loss (W/m) at same conditions as in pipe catalogue for different pipe types (steel, PEX, copper) and modifying thermal conductivity to match catalogue values.
- **Building/House Substation Model Changes**: Floor heating loop connected to SH loop, re-calibrated to supply fixed annual average value via adjusting floor UA-value.
- **Solar Buffer Storage**: No calibration. Used a theoretical value for the storage U-value.

Paper IV:

There were no calibrations made, although the employed mass flow in solar loop was adjusted to maximise the solar yield while achieving target outlet temperature.

2.3.6 Boundary conditions

Here is a breakdown of the key boundary conditions.

Input Data

Weather data was utilised in all papers, sourced from:

- **Papers II & III**: Meteonorm software for Kungsbacka, interpolated from nearby stations. Solar data corrected with satellite input.
- **Paper IV**: SMHI archive for Hemse (2015), processed via Meteonorm to create TRNSYS input files (.tm2).

DHW profiles (Paper II–III):

- **Papers II & III**: Based on guidelines for DHW consumption per person (Swedish standards [41]), assuming three persons per household.
- The DHW profiles were calculated with DHWcalc [37] (see introduction to Ch. 2 for more information). The input data used are presented in Table 4.
- Two DHW profiles were created, each for 50 houses, resulting in a DHW load for 100 houses in total. See *section 2.3.2.1* for details on this. The idea behind this was to get a more appropriate coincidence factor for the DHW, a smaller group (25 houses) provide higher peaks with about 25% lower coincidence factor and 50% lower daily DHW volume, than for a larger group (50 houses). The end result is that the larger group has a higher frequency of draw-off, with less pronounced dynamic effects (low return temperatures) affecting solar yield. This was assumed more suitable as the focus of the studies were on total energy rather than power. More information about this is found in the Paper II discussion, the main points of which are re-iterated in the thesis discussion (see *section 4.1.1.1*).

Table 4: Overview of input values used with DHWcalc for generating a DHW consumption profile to use as input in the simulation models developed in this Paper II/III.

	Kitchen	Washbasin	Shower	Bath
Share of total [%]	40	20	30	10
Draw-off rate [L/s]	0.2	0.1	0.2	0.4
Draw-off duration [min]	6	3	12	9

SH load (Paper II-III):

- **Papers II & III:** The house SH load is modelled using a two-zone building model based on drawings of a real house. One zone heated by mechanical ventilation system with auxiliary water-air heat exchanger (Max. 2 kW - varies) and heat recovery, the other by floor heating (0.1 kW - constant). The SH load depends on the ambient temperature fed by weather data, indoor set temperature is 19.5°C. Windows and shading are accounted for, together with internal gains from electricity use in equipment/appliances and passive gains from occupants. The gains are scheduled according to presumed occupancy time and average number of occupants per household.
- Total system load obtained as explained in *section 2.3.2.1.* This was deemed appropriate due to the simultaneity of heating loads exposed to the same ambient temperatures.

Total load profile (Paper IV):

Paper IV: total load profile was used as input (see Figure 4 - *section 2.1.2*). The supply temperature followed the ambient temperature, ranging from 85°C in winter (ambient temperature of − 10°C and lower) to 65°C in summer (ambient temperature 16°C and higher). The return temperature was calculated from the supply temperature and load in each time-step.

Control Card Settings (TRNSYS)

All simulations (*Paper II–IV*): Employed a 3-minute time step and set error message limit to 1000. Other settings were left at default.

2.4 Parametric studies

The parametric studies made were different for new and existing DH. The parametric study from **Paper III** and was based on changing insulation series for steel pipes, as well as the culvert type (i.e. the pipe-insulation assembly) for PEX pipes. The main parameter was pipe insulation class (and indirectly: U-value). The parametric study from **Paper IV** was based on changing the collector area and associated storage volume (constant specific volume). The main parameter was collector area (and indirectly: solar fraction).

2.4.1 New built systems

Table 5 and Table 6 list various pipe combinations used in **Paper III** to create different versions of the Hybrid and the GRUDIS distribution concept, respectively. The pipes in Table 5 are categorized based on their application in either the primary or secondary network, whereas Table 6 presents pipe for the entire network. Each distribution concept has a reference (ref.) pipe combination and insulation class specified, against which the other variants are compared in terms of energy performance and cost-efficiency.

The hybrid distribution concept includes variants H1 (ref.) to H8 with primary steel pipes (M1) and secondary pre-insulated PEX (PI-PEX) pipes (M1 and M3) or EPSPEX pipes (M3) with varying insulation classes. Series 1 insulation is thinner than series 2 insulation, with lower thermal resistance.

Table 5: Hybrid variants – Overview of different pipe combinations used to simulate variations (H2 – H8) of the hybrid distribution concept in Paper III. The pipe types are listed according to their application in either the primary or the secondary network. Abbreviations: ins = insulation.

		H1 (ref.)	**H2**	**H3**	**H4**	**H5**	**H6**	**H7**	**H8**
Primary	Pipe type	Steel (M1)	Steel (M1)	Steel (M1)	Steel (M1)	Steel (M1)	Steel (M1)	Steel (M1)	Steel (M1)
	Ins. class	Series 1	Series 2	Series 1	Series 2	Series 1	Series 2	Series 1	Series 2
Secondary	Pipe type	PI-PEX (M2)	PI-PEX (M2)	PI-PEX (M2)	PI-PEX (M2)	PI-PEX (M1)	PI-PEX (M1)	EPSPEX (M3)	EPSPEX (M3)
	Ins. class	Standard	Standard	Plus	Plus	Mixed	Mixed	NA[2]	NA[2]

[2] The EPS-casing has a square cross section, which means that the insulation class is not easily comparable to the insulation standards used for other pipes. No definition of the insulation class has been found, so this is defined as "not applicable" (NA).

The GRUDIS distribution concept consists of variants G1 (ref.) to G4 using PI-PEX and EPSPEX pipes with different insulation classes. The GRUDIS distribution concept is limited to PEX pipe technologies, resulting in only four variants. Different insulation levels are available for pipe sizes, where M2 offers dual insulation levels for all sizes compared to M1. The “standard” and “plus” insulation classes offered by M2 specifies insulation thickness, where standard is thinner than plus, similar to the difference between series 1 and 2 insulation, as described in the previous paragraph. M1 only provides a lower insulation level for specific pipe sizes, so that the term “mixed” insulation class us used when using PI-PEX pipes from M1.

The insulation class for EPS-casing pipes with square cross-sections is challenging to compare to standard insulation classes. Therefore, it is defined as "not applicable" as its insulation class definition is unavailable.

Table 6: GRUDIS variants – Overview of different pipe combinations used to simulate variations (G1 – G4) of the GRUDIS distribution concept in Paper III. Abbreviations: ins = insulation.

Variant	**G1 (ref.)**	**G2**	**G3**	**G4**
Pipe type	PI-PEX (M2)	PI-PEX (M2)	PI-PEX (M1)	EPSPEX (M3)
Ins. class	Standard	Plus	Mixed	NA[2]

2.4.2 Existing systems

Table 7 presents an overview of different system variants simulated in **Paper IV**, based on varying collector areas and heat supply configurations. The storage volume is proportional to the collector area, with specific volume of 0.1 m3 /m2 collector area chosen to maximise stored solar energy. Note that variant 1 features a 3 MW boiler, while the remaining variants all feature a 2.5 MW boiler due to the presence of a boiler buffer storage volume (*see section 2.3.3 for details*).

Table 7: System variants – overview of the simulated system configurations and their included components in Paper IV. Abbreviations: boiler-only (BO), Boiler + storage (B + ST), B + ST + flat plate/evacuated tube collectors (B + ST + FPC/ETC)

Variant	Configuration	Collector area [m^2]	Storage volume [m^3]
1	BO	NA	NA
2	B + ST	NA	100
3		500	150
4		1000	200
5		1500	250
6		2000	300
7	B + ST + FPC	2500	350
8		3000	400
9		5000	600
10		7500	850
11		10000	1100
12	B + ST + ETC	3000	400

2.5 Economics

The economics chapter is divided into three sections, whereby the first two deal with the new built DH systems and the last section deals with the existing DH systems. *Section 2.5.1* describes simple economics used in Paper II to provide indications on most cost-effective heat distribution systems out of three alternatives. *Section 2.5.2* describes more detailed economics used in Paper III to investigate potential cost benefits for two distribution systems indicated in Paper II to be more cost-effective[3] than conventional distribution using more realistic data and calculations. *Section 2.5.3* describes the input costs used for unit heat cost calculations in Paper IV to investigate the benefit of solar heating versus conventional heat supply in existing DH systems.

2.5.1 New district heating - Simple economics

In the work with Paper II, costs have been collected for the pipes used in the different distribution concepts. For steel pipes, prices were supplied by a manufacturer of pre-insulated steel pipes (Table 8) and for the EPSPEX culvert prices were supplied by another manufacturer (Table 9).

These costs were supplied directly from manufacturer, and excludes the cost of connections, welding and VAT. This thesis makes use of these data for presentation of a simplified analysis. In the analysis, the trench costs are calculated so that only 30% of the regular trench cost applies for buried solar pipes in parallel with the PC (double trench).

The distribution of pipe lengths sorted by nominal diameter can be found in *Paper II*. The analysis will present the total costs from these systems only and no intermediate calculations.

Table 8 shows the 2019 prices for pre-insulated steel twin pipes from manufacturer [42]:

Table 8: Prices (ex. VAT) on series 1 pre-insulated twin steel pipes from manufacturer [42].

Pipe dimension	DN80	DN65	DN50	DN40	DN32	DN25	DN20
Price [EUR/m]	70.4	62.9	53.5	39.2	38.2	34.3	34.3

Table 9 shows the 2019 prices for EPSPEX culvert from manufacturer [43]:

Table 9: Prices (ex. VAT) on EPSPEX culvert from manufacturer [43].

Pipe dimension	DN110	DN90	DN63	DN50	DN40	DN32	DN25
Price [EUR/m]	128.2	100.6	62.6	50.0	42.1	31.7	29.5

2.5.2 New district heating - Detailed economics

In **Paper III**, the simple economic analysis was elaborated into a more detailed economic analysis, based on calculations of the system costs using the software Wikells and tenders received from pipe suppliers.

The key performance indicator (KPI) for the analysis was the marginal life cycle cost (LCC_{mrg}), presented in *Eq. 1*. It accounts for the marginal initial capital costs (ICC) related to construction in

[3] The term “cost-effective” is used to designate better performance than some alternative, while the term “cost-competitive” is used to designate equal or similar performance (i.e. parity of unit heat cost).

addition to the other ICC of the other parts of the DH system, operation and maintenance costs (O&M), re-investment costs, and residual values.

The marginal LCC (eq. 1) looked at differences in ICC between the two distribution concepts investigated (Hybrid/GRUDIS), for the different variants presented in Table 5/Table 6.

$$LCC_{mrg} = ICC + A = \Delta ICC_{construction} + ICC_{pipe\ network} + ICC_{financial} + A_{maintenance} + A_{boiler\ fuel} \qquad (1)$$

Where ICC is the initial capital cost, A is the annual maintenance and operational (boiler fuel) costs. The LCC_{mrg} only includes differences in construction costs ($\Delta ICC_{constuction}$) and is lower than the total (or actual LCC), but is deemed sufficient as a means of comparison.

The main differences in ICC are as follows:

- **Construction Costs**: The GRUDIS system has higher boiler central construction costs due to central storage, whereas the Hybrid system incurs additional intermediate substation costs.
- **Pipe Network Costs**: GRUDIS uses PEX pipes, which are less costly than the steel pipes used in the Hybrid system. Installation costs vary based on pipe type and trenching requirements.
- **Financial Costs**: Higher ICC in the Hybrid system leads to greater financing costs compared to GRUDIS.

Regarding O&M costs; Maintenance costs are assumed equal for all variants of the two distribution concepts. Boiler fuel costs were influenced by boiler efficiency which depended on boiler load factor and solar collector degradation which was defined as a static annual value.

2.5.3 Existing district heating - Economic analysis

The economic analysis in **Paper IV** used levelised cost of heat (LCOH) as the main KPI. This was calculated using investment costs, O&M costs, energy output and discount rates for future cash flows. The equations for calculating the LCOH can be found in *Paper IV*.

Levelised cost of heat

The LCOH was divided into two types, defined as follows:

1. Net LCOH (nLCOH) – when retro-fitting a DH system.
   Covers costs related to solar components (investment, O&M). It also applies to boiler-only or boiler-and-storage configurations, where it includes the running costs of continued operation of the boiler and alternatively also the investment cost of a storage.

2. System LCOH (sLCOH) – when re-powering a DH system.
   For re-powered systems, includes costs of the entire system (boiler, solar heating components, O&M).

Simplifications used:

- Static annual heat generation for each variant simulated and thereby, static annual O&M costs.
- Zero depreciation and corporate tax rates.
- No residual value at economic life's end.
- Economic lifetime assumed at 30 years.

Solar heating system and storage costs

The solar collector costs used were:

- FPC: 240 EUR/m^2.
- ETC: 395 EUR/m^2.

The values are for turn-key systems, excluding VAT and subsidies.

The storage costs were calculated according to a mathematical formula using the storage volume as the sole variable.

Boiler system costs

The boiler system costs are divided into investment costs and O&M costs, whereby a static component is calculated based on the boiler capacity and a dynamic component is calculated based on the supplied boiler energy. The applied costs are presented in Table 10. The fuel costs are based on values in Table 11.

Table 10: Boiler costs – investment and O&M costs for a biomass boiler used in Paper IV.

Boiler type	Investment [EUR/kW]	Static O&M [EUR/kW]	Dynamic O&M [EUR/MWh]
Biomass	805.6	10.1	2.0

Table 11: Fuel costs – Costs for various fuels, used both in main boiler (wood-pellets) and backup boilers in Paper IV. Abbreviations: diesel fuel oil (DFO), fuel oil – heavy (FOH), electricity (EL).

FUEL	Wood-pellets	Bio-oil	DFO	FOH	EL
[EUR/MWh]	31.4	62.9	165.3	88.2	84.8

Operating costs during boiler maintenance

The operating costs of the DH system was investigated for the period of main boiler maintenance in July, when heat demand was low.

Fuel use was calculated for:

- Oil boiler (85% static efficiency).
- Electric boiler (95% static efficiency).

Static efficiency assumptions were considered appropriate due to oil/electric boilers having high efficiencies due to fast start-up and high turndown ratios. Electric boilers have slightly higher efficiency due to lack of flue losses in addition to the short start-up time.

The analysis was performed by:

- Summing up heat demand for July from simulation models.
- Dividing demand by boiler efficiency to estimate fuel use.
- Calculating the fuel cost from fuel use by main/backup boiler (Table 11).
- Results compared to using wood-pellets in the main boiler to assess backup-boiler fuel cost impact on LCOH.

2.6 Sensitivity analysis

Various sensitivity studies have been performed to investigate validity of results across changing boundary conditions.

The work on new DH features two sensitivity studies in addition to the parametric studies that make up main results, where the first study (*Paper II)* on sensitivity of results to line heat density is presented in *section 2.6.1* and the second (*Paper III*) on cost sensitivity of fuel costs and interest rates is presented in *section 2.6.2*.

The work on existing DH features (*Paper IV*) three sensitivity studies in addition to the parametric studies making up the main results. The first study investigates impact of changing the specific storage volume per collector area in solar heating system dimensioning and is presented in *section 2.6.3*. The second study is about the economic boundaries like employed costs and interest rates and is presented in *section 2.6.4.* The third study, not included in paper IV, concerns the impact of lower return temperatures and is presented in *section 2.6.5*.

2.6.1 New district heating – line heat density

In *Paper II* the sensitivity analysis was made by simulating the three different distribution systems and varying line heat density (LD). The logic was to investigate competitiveness of the different distribution concepts across different settlement characteristics in terms of population density (and hence heat density). Urban areas (i.e. cityscape) typically feature dense DH networks, for which energetic and economic performance is typically satisfactory. However, suburban areas typically would feature sparse DH networks, while rural areas would have very sparse DH networks. One DH network can include several areas of different density, so the designation is not unanimous, although for the sake of clarity, the study looks at variation of LD for an entire area.

Three values of LD were employed by changing the pipe network length, from 1 to 2 and 4 times the initial value, corresponding to 1, 0.5 and 0.25 times the initial LD, respectively. The energy balance for all simulations were normalized to the energy balance of the Hybrid system at initial line heat density (1LD). The initial line heat density (1LD) of the DH systems simulated was 0.2 MWh/m and was considered representative of a sparse DH network. This means that 0.5LD and 0.25LD corresponded to 0.1 MWh/m (very sparse DH) and 0.05 MWh/m (extremely sparse DH), respectively. The extremely sparse DH was included to provide information about distribution concept feasibility in what was considered the "lower limits" of DH.

2.6.2 New district heating – cost sensitivity

In *Paper III* the sensitivity analysis was made by variation in cost calculation variables. The background was an economic calculation of LCC for a lifetime of 20 years, for which the interest rate (IR) and annual boiler fuel cost increase (FCI) was varied.

An IR of 2%, 4% and 6% was designated IR1, IR2 and IR3, respectively, while the same variation in FCI was designated FCI1, FCI2 and FCI3 respectively.

The choice of values for FCI was founded on the 2% inflationary target of most central banks for the lower value, while the higher values were chosen for simplicity. Although fuel costs may increase more than inflation due to market conditions, the chosen range of values were assumed representative at the time, despite that cost development in recent years have made these rates rather conservative. However, over a longer period of time (i.e. 20 years), it is assumed that the FCI rate will even out and converge to a value in line with those studied here. Some remarks about this are provided in the discussion.

2.6.3 Existing district heating – Storage volume

In *Paper IV* the first sensitivity analysis investigated a change in storage volume for variant 9 (see *Table 7, section 2.4.2*) which comprised 5000 m^2 of FPCs. The specific storage volume was varied between 0.1 m^3/m^2 and 0.3 m^3/m^2, corresponding to a total volume between 600 m^3 and 1600 m^3, respectively, in order to evaluate the impact on solar yield and LCOH. The aim was to validate the initial assumption on required storage volume for satisfactory collector performance and reveal any cost-efficient improvement measures to the solar heating system.

2.6.4 Existing district heating – cost sensitivity

Two types of sensitivity analysis were conducted aiming to assess solar heating competitiveness under varying economic conditions and provide design guidelines for DH systems:

- Sensitivity of LCOH. Done by changing the discount rate in the calculation formula.
- Sensitivity in fuel and collector cost to reach parity between solar and non-solar DH. Done by varying fuel costs while iteratively adjusting collector costs to achieve parity between solar and non-solar DH system costs. Parity fuel cost values were calculated at reference collector costs for a 3000 m^2 solar (FPC/ETC) system as this had the lowest LCOH of all non-solar variants.

Based on this threshold fuel costs and collector costs were obtained that determine cost-competitive conditions for solar heating system.

2.6.5 Existing district heating – lower return temperatures

An additional sensitivity study was made in the context of this thesis, in order to investigate the impact on solar heating system performance, when lowering the network return temperature to the boiler central. This was done by reducing the return temperatures simulated in *Paper IV* by -5 and -10 degrees, respectively. Hence, simulated return temperatures were in the interval 38°C - 56°C and 33°C - 51°C, respectively (*see section 2.1.2* for original temperatures).

2.7 Key performance indicators

The key performance indicators (KPI) used for evaluating results are divided into two sections; one for new built systems and one for existing systems, while some common KPIs are listed here in the subchapter introduction.

Life Cycle Cost (LCC)	Total costs over system economic lifetime (Calculation: Paper III).
Solar Fraction (SF)	Ratio of stored solar energy to total energy demand (Calculation: Paper II)

2.7.1 New built district heating systems

The following KPIs are used only in *Paper II and III:*

Energy balance	Energy budget for energy supply and demand in the DH system.
$NUSE_{SYS}$	Ratio of solar energy to house heat demand (ex. distribution losses - Calculation: Paper II).
Performance ratio (PR)	Ratio of house energy demand to boiler energy supply (Calculation: Paper II).
Q_{boiler}	Energy supplied from boiler to flow stream, excluding losses.
$Q_{BC\ loss}$:	Losses from solar buffer storage(s) and internal connection pipes.
$Q_{dist\ loss}$	Losses from ground buried pipes and any intermediate substation(s).
Q_{ETC}	Solar energy from evacuated tube collectors, minus solar pipe losses.
Q_{FPC}	Solar energy from flat plate collectors, minus solar pipe losses.
$Q_{house\ tot}$	Total SH and DHW demand of the houses in the DH network.
$Q_{solar\ st.\ loss}$	Losses from FPC solar storage plus internal connection pipes.

2.7.2 Existing district heating systems

The following KPIs are used only in *Paper IV:*

Q_{FB}	Fuel supplied to boiler.
Q_{BE}	Energy supplied from boiler.
Q_{LB}	Losses from boiler (stack).
Q_{BC_loss}	Internal heat loss in boiler central (pipes and storage).
Q_{col}	Solar energy delivered from collectors.
Q_{sol}	Solar energy delivered to storage charge loop.
Q_{sol_loss}	Solar energy lost in solar loop.
Q_{load}	Heat demand of load (DH network).
SF	Solar fraction: Ratio of solar energy loaded into store to total energy supplied.
Y_s	Specific yield: Supplied solar energy per unit collector area.
LCC	Life cycle cost.
sLCOH	System LCOH - including boiler investment cost.
nLCOH	Net LCOH - excluding boiler investment cost (solar LCOH).

3. Results

This chapter presents the results for new district heating in *subchapter 3.1* and for existing district heating in *subchapter 3.2.*

3.1 New district heating

This subchapter mainly summaries from *Paper II and III.*

Two energy balance comparisons are summarised in *section 3.1.1*, where one comparison includes three distribution concepts and provides the reasoning the other comparison where the scope is reduced to two distribution concepts.

3.1.1 Energy balance

The energy balance is divided into two sections, where the first treats the comparison of three distribution concepts and acts as motivation for increased scrutiny of the two concepts presented in the second section.

3.1.1.1 Three distribution concepts

Figure 13 shows the annual energy balance from *Paper II*:

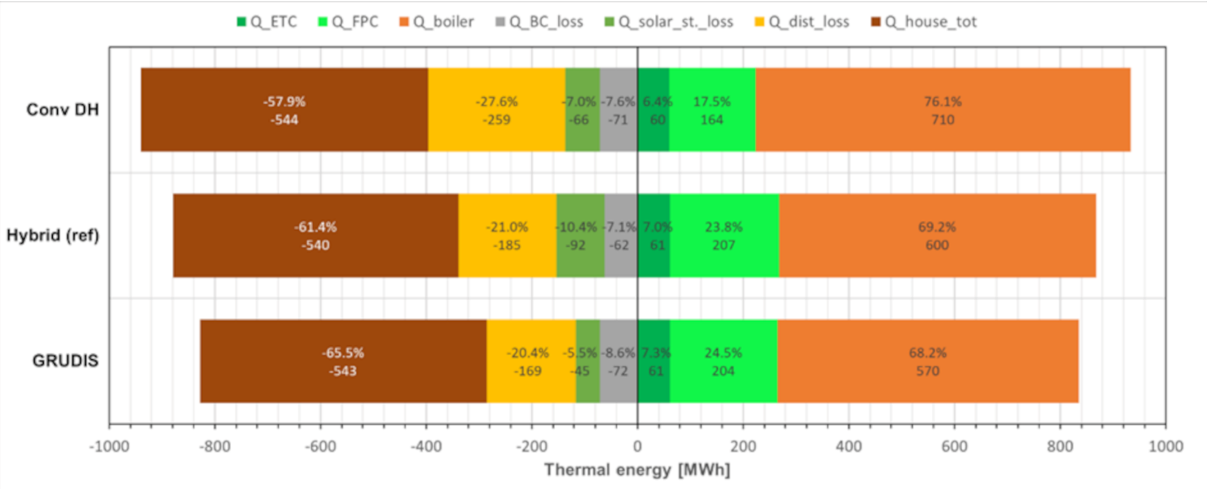


Figure 13: Comparison of simulated energy balance for the Conventional, Hybrid and GRUDIS distribution concepts investigated in Paper II. The relative share of the energy supply/demand is shown in percent.

In the Paper II energy balance, in particular one result stands out; the conventional DH concept performs worse than any of the available system alternatives, having a performance rate (PR) of mere 58% and utilising 110 MWh more boiler-supplied energy than the reference system, with a significantly lower SF of 24%.

Aside from this, the difference in boiler-supplied energy between the Hybrid (reference) and All GRUDIS system was 30 MWh (5%), with the latter having the lowest value, while the performance ratio (PR) was 61% and 66% for the Hybrid (reference) and All GRUDIS system, respectively. Thus, according to this, *the results appear to indicate that All GRUDIS is slightly more resource efficient from an energy perspective.* The solar fraction was similar for the Hybrid system (31%) and the All GRUDIS system (32%) with an absolute difference in solar energy of less than 3 MWh. The overall losses are 53 MWh (19%) higher in the Hybrid system, which is unproportionate to the difference in fuel and reflects the difference in system efficiency. The majority of these losses are related to the solar storage losses, which in the Hybrid system are more than double those in the All GRUDIS system. These additional losses result from the intermediate substation and additional solar piping associated with the Hybrid distribution concept where solar is semi-decentralised. Furthermore, in the All GRUDIS system, the whole distribution heat loss can be covered by solar during summer, whereas in the Hybrid system, only the secondary network heat loss is covered by the solar. This leads to a larger part of the solar heat being lost in the Hybrid system, despite similar yields. Hence, the observed difference in overall heat loss is due to a combination of higher heat losses in the solar heating system and the distribution network, whereby the primary distribution heat loss is the main reason for the difference in boiler supplied energy.

3.1.1.2 Two distribution concept variants with different pipe types

Figure 14 shows a comparison of the energy balance for the GRUDIS and Hybrid distribution concepts from **Paper III**. The variant G1 and H1 have very similar absolute values of both heat supply and consumption/losses (the values for boiler energy and distribution losses have been added to the graph for clarity), with some differences in relative shares of boiler central losses and solar storage losses. These losses follow due to the same reasoning as presented in the previous section, where the solar storage losses are smaller in the GRUDIS system. On the contrary, the larger boiler central losses follow from a larger boiler central and more internal losses. Despite these differences, the total losses are comparable. Therefore, based on the presented results, it is clear that based on the applied insulation level, the two distribution concepts can be regarded as equally well performing.

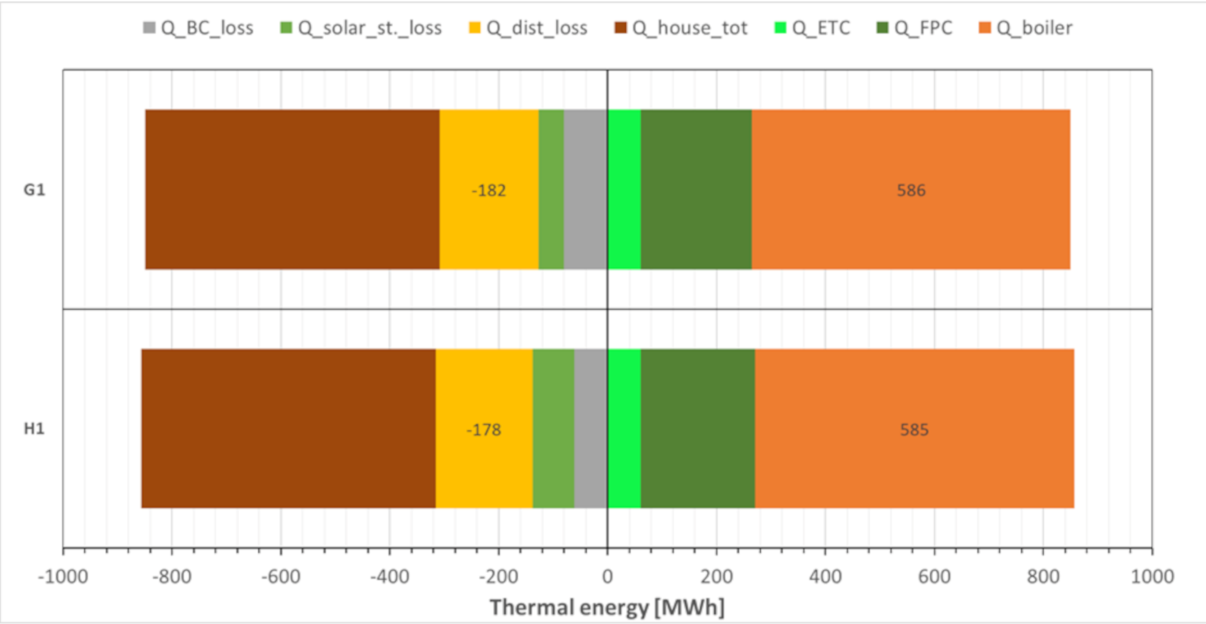


Figure 14: Comparison of the energy balances in Paper III for the Hybrid and GRUDIS reference distribution concepts H1 and G1, respectively.

The intercomparison of the results with those for Paper II (Figure 13) is not straightforward, as the applied insulation level is different in the two papers. From the presented results, it is clear that variant G1 from *Paper III* has higher distribution losses than for the GRUDIS alternative in *Paper II* (Figure 13), which indicates less insulation, while the other losses are comparable. For variant H1, the opposite is true, so the *Paper III* losses are lower than the same variant in *Paper II*. However, the difference in distribution losses is less than 5%, which limits the significance of the results. Here it is worth noting that the observed differences, despite being small, seem consistent with the employed values in the models of the different papers. In particular, the heat conduction coefficient of the pre-insulated steel pipe model in Paper III was lower than that in Paper II, which can explain the lower losses in *Paper III*.

Regarding the differences between papers in results for the GRUDIS concept, the heat conduction coefficient is the same in the pipe model for both papers, so the observed differences are due to difference in network length, where the overall heat loss of the network is larger in variant G1 of *Paper III*, than in the GRUDIS variant in *Paper II* (more detail on this can be found in Table 10 of *Paper III*).

Nonetheless, as will be apparent from the following parametric study *(section 3.1.3*), the shown results are consistent between papers and therefore, the best (energetically) performing distribution concept depends on applied insulation series. However, as will be seen in the economic analysis, the overall (techno-economic) performance is independent of this.

3.1.2 Economics

This section presents part of the underlying motivation behind the research evolution, as the energetic performance improvements for the GRUDIS concept was shown to hold economic promise as well, which is outlined in *section 3.1.2.1*, before being developed in more detail in *section 3.1.2.2*.

3.1.2.1 Simple economics

The simple economic analysis made in **Paper II** aims to present a logical basis for the decision to proceed with a deeper study (*Paper III*) into detailed economics of the hybrid and All GRUDIS system configurations. In the analysis, the pipe distribution is well known for all systems and the pipe costs do *not* include installation and welding. The costs used are all ex. VAT, as is customary in commercial price catalogues.

Table 12 shows an overview of estimated system costs for the three distribution systems evaluated in *Paper II*, including potential costs for substations in the Hybrid and Conventional DH system. It is worth noting that the costs presented in Table 12 do not include costs of a larger BC to house additional storage for the centralised FPC solar heating system included in the GRUDIS/conventional DH system. This is investigated further in *Paper III* and presented in *section 3.1.2.2*.

Table 12: Overview of the estimated distribution network costs for the three distribution concepts evaluated in Paper II. All costs are in 10^3 EUR. *Total costs do not include the costs for a large BC in GRUDIS and conventional DH system.

		Hybrid	GRUDIS	Conventional
Network length (steel/PEX)	[m]	340/2240	-/2580	2580/-
Solar culvert[4]	[m]	280	410	410
Cost pipes	[k EUR]	120	140	130
Cost trench	[k EUR]	460	450	450
Intermediate substation	[k EUR]	240	0	0
House substation	[k EUR]	200	200	600
Total*	[k EUR]	1020	790	1170

In summary, the simplified economic analysis presented here shows that the use of EPSPEX only (All GRUDIS) in a heating system has a hard time meeting the competition from the Hybrid system, if only the pipe costs are considered. This would be in line with previous results indicating that an EPSPEX

[4] The length of the solar culvert for the GRUDIS and conventional concept that is presented in *Paper II* are incorrect. The values presented in Table 12 are the correct ones. Nonetheless, the pipe and trench costs presented have been controlled and found to be correct in both *Paper II* and here.

system is best used as a secondary system [34]. However, if additional costs are taken into account, such as those for intermediate substations in the Hybrid system or those for house substations in the Conventional DH system (i.e. for a system built anew), the All GRUDIS system will probably require significantly lower investment costs. *The conclusion is thus far that the All GRUDIS system seems to be preferable economically, although more detailed calculations are needed to support this.*

3.1.2.2 Detailed economics

The economic analysis made in **Paper III** picked up the demand for more detailed calculations that were outlined in *Paper II*. Figure 15 shows the LCC for the two reference distribution variants G1 and H1, presented in Figure 14 based on an economic lifetime of 20 years. Thea absolute value for the LCC is 15.5 M SEK and 20.4 M SEK for the G1 and H1 variant, respectively. Thus, the LCC is 4.9 M SEK or about 24% lower for the GRUDIS concept, which indicates *a significant advantage* over using the Hybrid concept. Due to the very similar energetic performance, the boiler fuel costs in the two systems concepts are very similar as well. Furthermore, despite higher costs for solar pipes, the lower costs of PEX distribution pipes give equally high total pipe costs. However, the construction costs are significantly lower in the GRUDIS concept, which leads to much lower financial costs and in the end, these two cost factors give the GRUDIS concepts its advantage.

In summary, the GRUDIS concept is significantly more cost-efficient than the Hybrid concept.

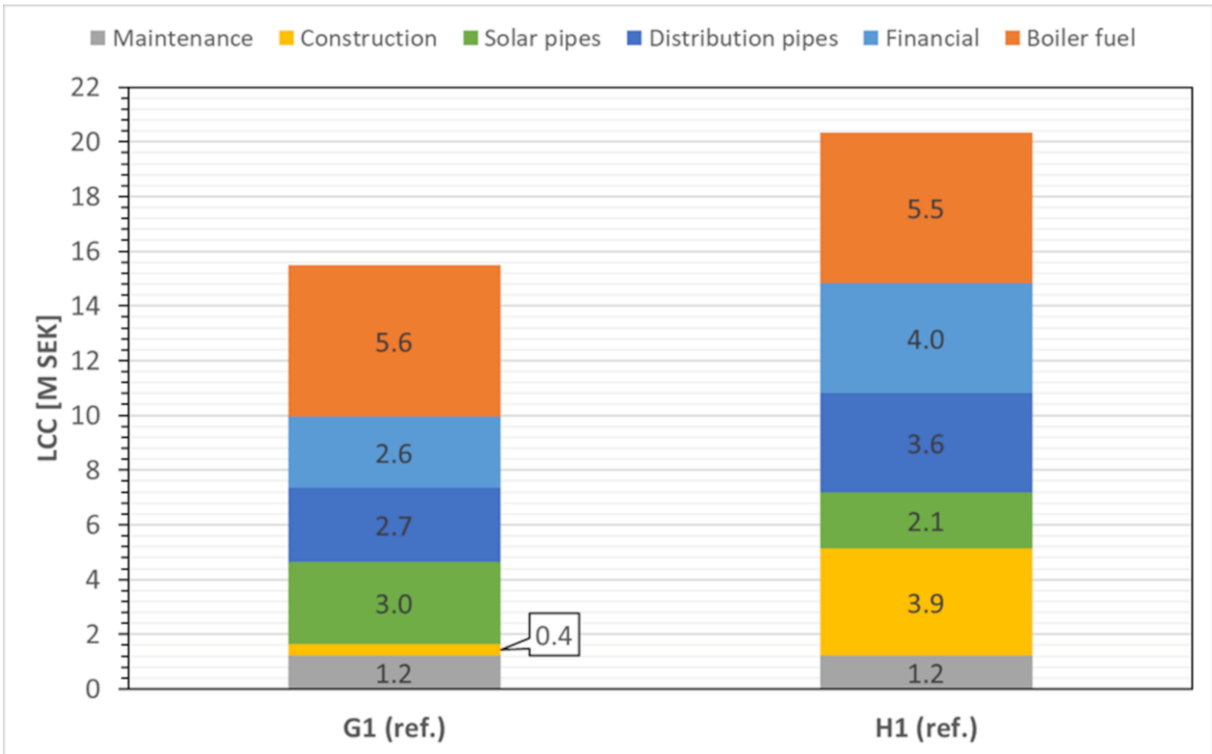


Figure 15: LCC analysis - Overview of the LCC of the two reference variants for the two distribution concepts simulated in Paper III with an economic lifetime of 20 years.

3.1.3 Parametric studies - pipe type and insulation series

The parametric study made in **Paper III** shows how the energy balance and LCC varies with insulation level of the pipe network for the GRUDIS and hybrid distribution concept. The difference in energy balance compared to the reference variant is shown for the GRUDIS concept in Figure 16 and the hybrid concept in Figure 17. The reference variant G1 had a distribution heat loss of 182 MWh, while the reference variant H1 had a distribution heat loss of 178 MWh. Based on these results and the employed insulation degree, it is apparent that the variants with lower heat losses correspond to higher insulation degrees and vice versa (see Table 5 and Table 6). Thus, variant G2 has the lowest distribution loss of all the GRUDIS variants and variant H4 has the lowest loss of all Hybrid variants. However, the relative difference between variant G1 and G2 and between variant H1 and H4, is only 4% and 5%, respectively. Hence, the energetic performance is similar for most variants, with minor performance differences for these variants and variants G3 and H3. The remaining variants show negligible differences.

Note that the variants G4 and H7 corresponds to the GRUDIS and Hybrid distribution concept in *Paper II*, respectively. Unfortunately, due to a change in the insulation heat transfer coefficient for steel pipes in *Paper III*, the heat losses do not correspond between *Paper II* and *Paper III* for the Hybrid concept and variant H7, respectively. However, the distribution heat losses for the GRUDIS concept in *Paper II* was 169 MWh can be calculated using the distribution heat losses from Paper III for variant G1 (182 MWh) and the presented figures for ΔQ (G4; -13 MWh), validating that the results are consistent between the models of the two papers. Accordingly, the GRUDIS concepts appears better from an energy perspective when looking at variant G4 and H7, but due to the similar results for the reference variants and the presented values of ΔQ, the energetically most favourable appears to depend on insulation degree. However, as was explained in previously, the differences are 5% at most, which reduces the significance of pipe insulation degree on the energy balance in the conducted studies.

Turning to the economy, the most favourable distribution concept is less dependent of insulation degree. Figure 18 shows the absolute cost difference for variants of the GRUDIS and Hybrid distribution concepts compared to the reference variants for each concept. As presented in *section 3.1.2.2*, the LCC was 15.5 M SEK for reference variant G1 and 20.4 M SEK for the reference variant H1. According to the results in Figure 18, variants G4 and H4 show the largest net differences (red diamond) in LCC, closely followed by variants G2 and H3, respectively. However, because the differences in LCC are rather small when compared to the total LCC and make out less than 2% between variants of the same concept, this indicates that investing in a higher degree of insulation does not significantly change the total LCC, despite leading to significant changes in distribution heat losses and boiler energy (as seen when Figure 16 and Figure 17 is compared with Figure 18).

Hence, considering that the difference between reference variants G1 and H1 was 24%, this means that the GRUDIS concept is more economic than the Hybrid concept, regardless of insulation level. Thus, despite the energetically favourable distribution concept depending on choice of pipe type and insulation degree, the economically best concept does not.

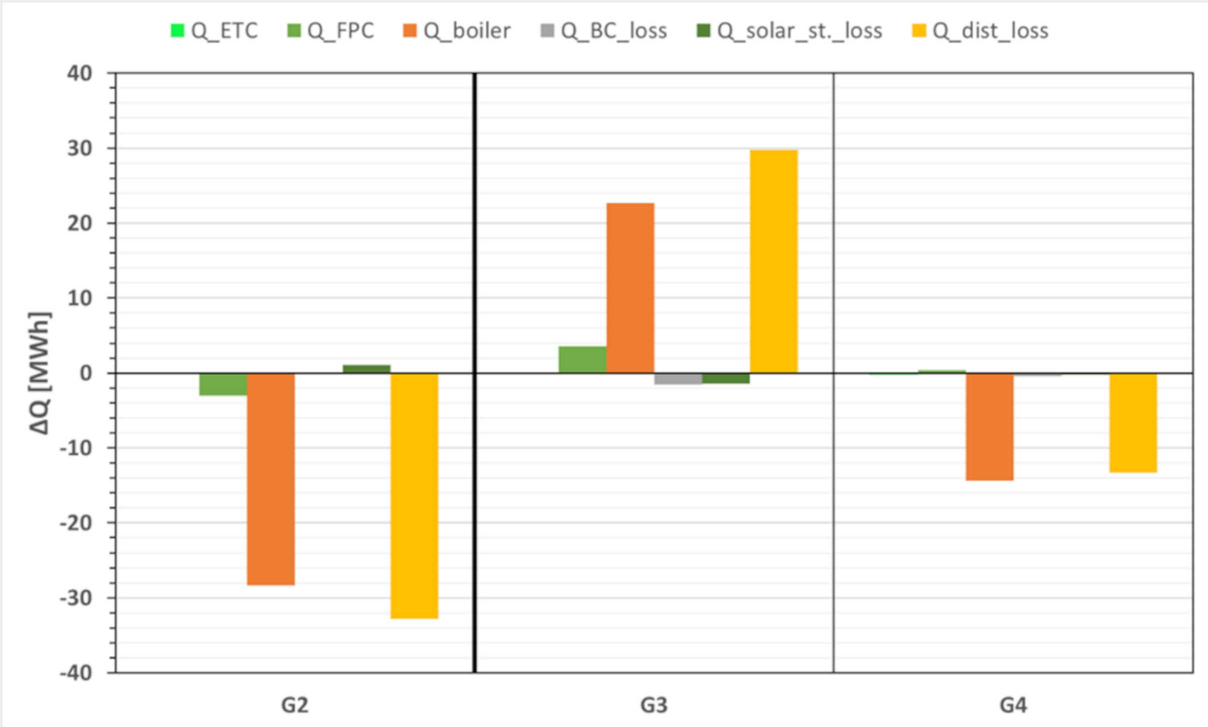


Figure 16: Paper III - Absolute changes in lost and supplied energy compared to the reference variant (G1) for the variants of the GRUDIS concept. The bold line indicates a change in pipe manufacturer; G1 and G2 employ M2, while G3 and G4 employ M1 and M3, respectively—see Table 6 for overview.

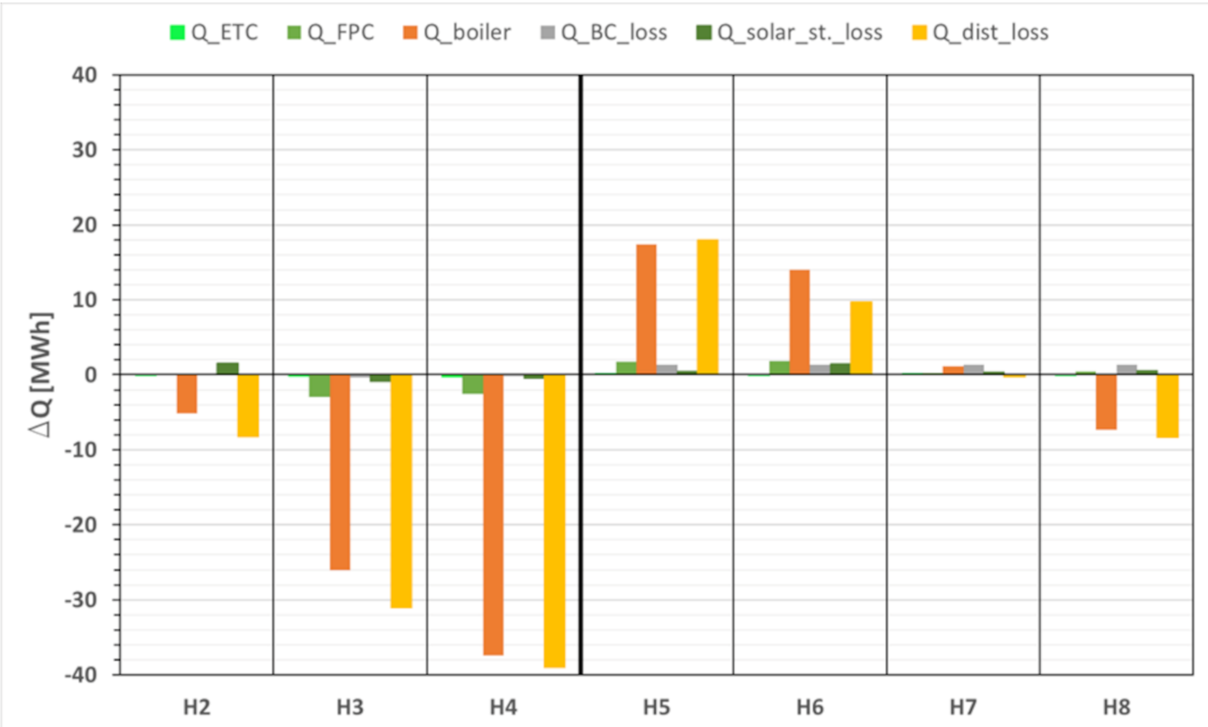


Figure 17: Paper III – absolute changes in supplied and lost energy compared to the reference variant (H1) for the variants of the hybrid distribution concept. The bold line indicates a change in the manufacturer of PEX pipes; H1–H4 employ PEX M2, while H5–H8 employ M1 and M3—See Table 5 for an overview.

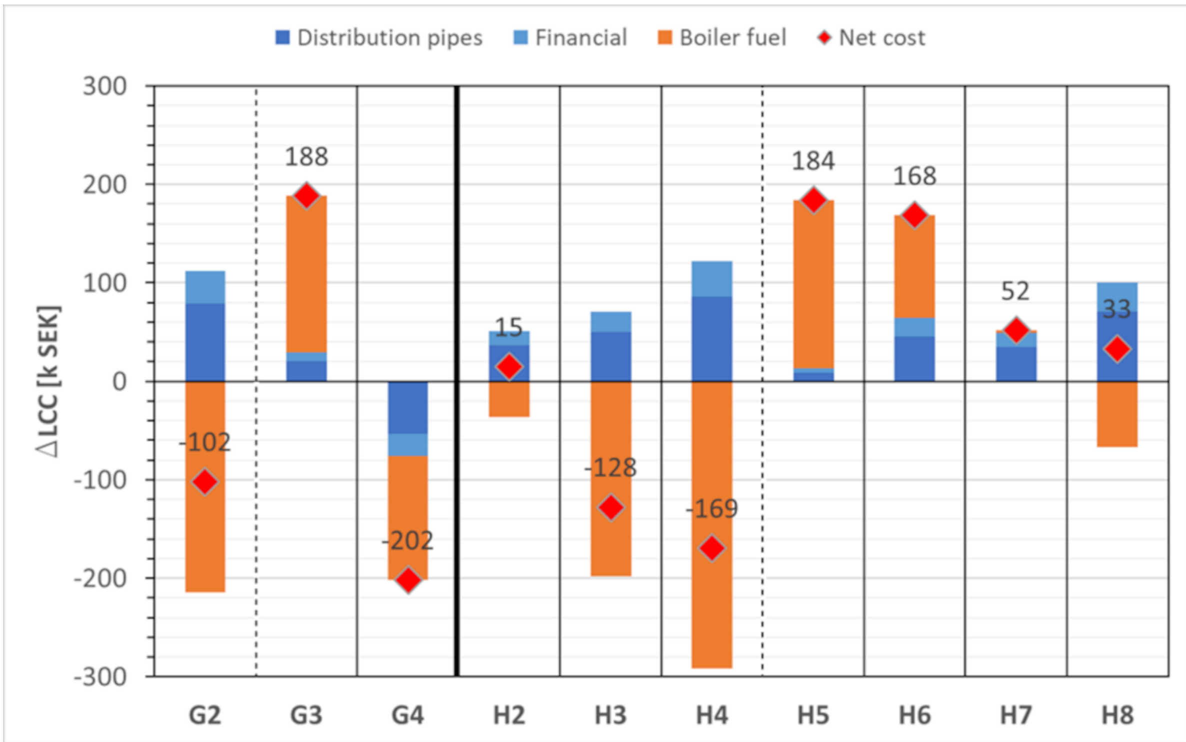


Figure 18: Paper III – Absolute cost change for the variants of the GRUDIS and hybrid distribution concept relative to the reference variant (G1 and H1, respectively). The bold line separates variants of different distribution concepts, while the dashed line separates reference pipe manufacturer(s); G2 and H2 – H4 employ PEX M2, while G3 and G4 as well as H5 – H8 employ M1 and M3. See Table 5/Table 6 for an overview.

3.1.4 Sensitivity analysis

The sensitivity study in *section 3.1.4.1* investigates range bound limitations in line heat density of heat distribution concepts, while *section 3.1.4.2* investigates the limitations of economic boundary conditions on these concepts.

3.1.4.1 Variation in line heat density

The initial line heat density of the DH systems simulated was 0.2 MWh/m, as for *Paper II*.

The methodology employed was to change the pipe network length to 2 and 4 times the initial value, corresponding to 0.5 and 0.25 times the initial LD, respectively. The energy balance for all simulations were normalized to the energy balance of the Hybrid system at 1LD (see Figure 13).

Figure 19 shows the sensitivity analysis based on linear heat density (LD) in *Paper II*. Note that the simulated absolute values are normalized to those at 1LD. Also note that the variable names ("Boiler", "ETC solar", etc.) correspond to the subscript of KPIs presented in *section 2.7.1* (essential denoting boiler supplied heat, heat from ETC solar collectors, etc., respectively).

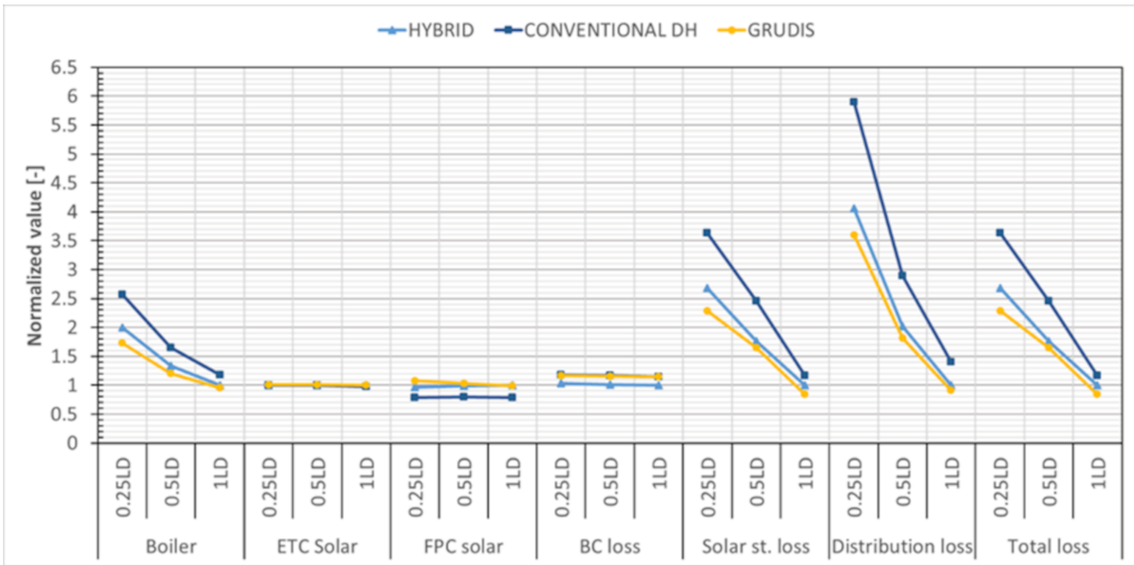


Figure 19: Paper III - Sensitivity analysis based on line heat density (LD). The simulated absolute values for heat input and losses at 0.25LD and 0.2LD are normalized to those at 1LD for the Hybrid system.

The result of the sensitivity analysis can be summarised as follows:

1. The distribution heat loss and supplied boiler energy are significantly influenced by the variation in network LD in different district heating systems. The losses are highest both in conventional DH due to twin-steel pipes, while they are lowest in the GRUDIS system because of PEX culverts (this is valid both for normalised and absolute values).
2. The total losses in the hybrid and GRUDIS systems are lower compared to the conventional DH system, especially in very sparse networks. Conventional DH is not suitable for such sparse networks based on the high loss fraction.
3. The GRUDIS system demonstrates lower distribution and total losses, leading to lower boiler energy consumption across all LDs in comparison to the Hybrid system. However, the differences between GRUDIS and Hybrid are minimal in regard to solar fractions in sparse (1LD) DH networks.
4. As the network density decreases, the solar yield increases for GRUDIS but decreases for the hybrid system, resulting in a higher boiler energy demand in the latter due to increasing losses.
5. Increasing heat density benefits the Hybrid and Conventional DH systems more in terms of reducing boiler energy compared to the GRUDIS system, showing the importance of heat density in systems with steel pipes and higher network temperatures. This trend suggests that differences in performance between system types will diminish as line heat density increases beyond that which is shown here.

3.1.4.2 Variation in fuel cost and interest rate

The sensitivity study made in *Paper III* included changing the interest rates and annual fuel cost increase as outlined in *section 2.6.2* to examine how changes in economic boundary conditions impact the Life Cycle Costs (LCC) of different distribution concepts. The results show (Figure 20) that while the absolute difference in LCC between reference concepts (G1 and H1) remains consistent regardless of fuel cost increases, it varies with increasing interest rates. The GRUDIS variants exhibit a slightly faster (relative) cost increase with fuel cost increments compared to hybrid variants, but are less affected by increasing interest rates due to differences in individual cost contributions to the LCC.

The sensitivity analysis highlights the importance of boiler fuel costs in the LCC calculations. Due to the significantly larger relative share (38%) of boiler fuel costs in the GRUDIS concept compared to that (28%) of the hybrid concept (see Figure 15), any absolute increase in boiler fuel costs has a more significant impact on the LCC of the former. Conversely, the financial and construction costs have a more substantial relative impact on the LCC of the hybrid concept than the GRUDIS concept. These costs make out about 66% of the LCC in the hybrid concept, compared to 54% in the GRUDIS concept.

To conclude; The comparison of the cost difference reveals that the GRUDIS distribution concept remains economically favourable regardless of variations in economic factors. The analysis indicates that the GRUDIS concept consistently provides cost savings across a range of boundary conditions, making it the preferred option.

The results of the sensitivity analysis in *Paper III* emphasises the influence of economic boundary conditions on the performance and cost-effectiveness of different distribution concepts, particularly in terms of LCC variations with changes in fuel costs and interest rates. The findings suggest that understanding these impacts is crucial for making informed decisions regarding the selection and optimisation of distribution concepts.

Figure 20 shows the absolute difference in LCC between distribution concepts for reference variants G1 and H1 on the left vertical axis and indicated by blue bars. The relative LCC change (increases) compared to the LCC at FCI 2%/IR 2% is shown on the right vertical axis and is indicated with an orange stapled line and a yellow solid line, for reference variants G1 and H1, respectively. Similarly, the relative LCC change for the most energetically efficient variants G4 and H4 is shown with a red triangle and green circle, respectively.

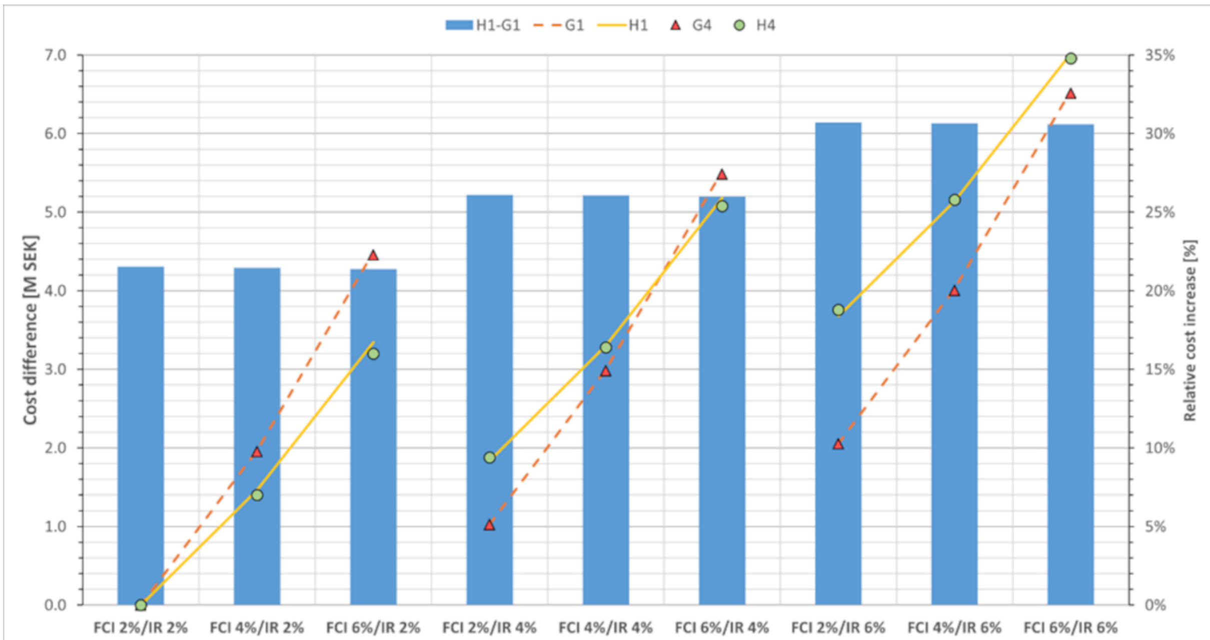


Figure 20: Paper III – Cost difference between reference concepts G1 and H1 (left axis – blue bars), as well as relative cost increase (right axis) for variants G1 (orange stapled line), G4 (red triangle), H1 (yellow solid line) and H4 (green circle), with changing fuel cost increase (FCI) and interest rate (IR). Relative values are calculated using FCI 2%/IR 2% as reference.

3.2 Existing district heating

This chapter provides a summary of results from **Paper IV** in section *3.2.1 Techno-economic analysis* and *3.2.2 Sensitivity analysis*.

3.2.1 Techno-economic analysis

The techno-economic analysis was divided into two sections in accordance with the original structure provided in **Paper IV**. In the first section, a boiler-only (variant 1) and boiler with storage system (variant 2) is compared to a solar assisted system with variation in collector area (variant 3 – 11) in *section 3.2.1.1*, both when keeping and replacing the existing boiler. In *section 3.2.1.2*, a solar assisted system with evacuated tube collectors (variant 12) is compared to selected other variants. See *section 2.4.2* for description of the parametric study and Table 7 for an overview of the system variants.

3.2.1.1 Boiler with/without storage and with/without solar flat plate collectors

The results of the parametric study with variation in storage volume and FPC are presented in Figure 21. Figure 21 shows the simulated boiler fuel use ($Q_{\_FB}$), transferred boiler energy ($Q_{\_BE}$) and solar energy ($Q_{\_sol}$), along with calculated values for sLCOH (re-powering case) and nLCOH (retrofit case) for non-solar variants 1 - 2 and solar variants 3 – 11.

From the figure, it can be seen that variant 2 with a smaller boiler of 2.5 MW and installed buffer storage shows a 5% reduction in fuel use and a 6% decrease in sLCOH compared to Variant 1 (3 MW boiler and no storage), making this a cost-efficient system option whether combined with solar or not. The investment in storage leads to more stable boiler operation and improves performance by avoiding excessive cycling which reduces heat cost.

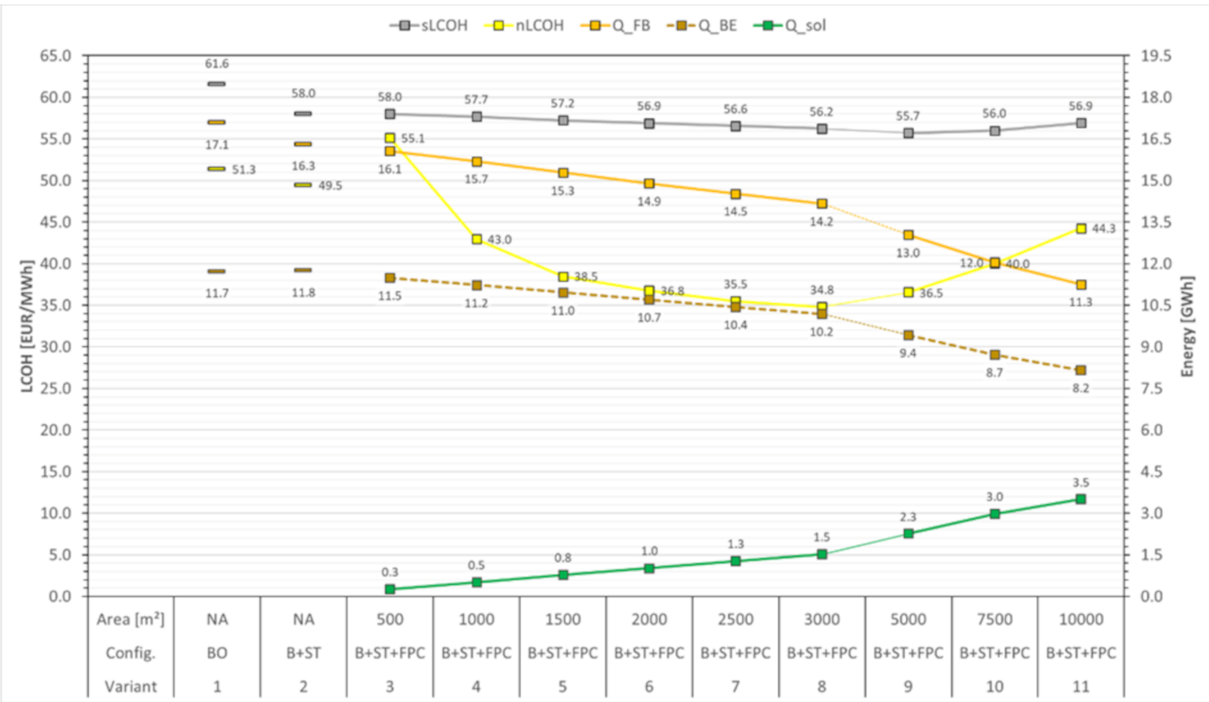


Figure 21: Energy use and heat cost – overview of energy use and resulting LCOH for variant 1 – 11 simulated in Paper IV. Abbreviations: boiler fuel use (Q_FB), transferred boiler energy (Q_BE) and solar energy (Q_sol). Beware the non-linear x-axis in the figure.

Furthermore, for the re-powering scenarios (replacing existing boiler with new), variants 2 - 11 (2.5 MW boiler) perform similarly to a boiler-only system (variant 1 – 3 MW boiler), although a system with around 5000 m^2 of installed collector area (variant 9) achieves a significantly (8%) lower sLCOH of 55.7 EUR/MWh. However, because the heat cost is so similar between solar variants, other factors such as emissions reductions become important when considering different system configurations.

In the case of retro-fitting (keeping existing boiler), a solar heating system proves to be a good strategy for reducing energy costs. All except solar variant 3 have lower unit heat costs than the boiler-only system (variant 1), indicating that having a solar heating system with 1000 m^2 or more collector area is cost-effective. The most cost-effective system is variant 8, which at 13% solar fraction demonstrates a 32% lower nLCOH compared to Variant 1. Solar installations larger than 3000 m^2 of collector area yield diminishing returns, suggesting a cost-efficiency limit around this point.

Figure 22 compares the performance of the solar variants and shows how the specific yield (Y_S), solar fraction (SF) and heat cost (sLCOH/nLCOH) varies with installed solar collector area.. It provides some of the same information as Figure 21, but with an improved view of the correlation between LCOH and solar heating system performance. As can be seen, the specific yield decreases for collector areas above 3000 m^2, which supports a cost-efficiency (and utilisation) limit around this solar heating system size. Variants up to 3000 m^2 of FPC collector area exhibit similar specific yield values, but this starts declining rapidly beyond this point, losing 31% over the range of 3000-10000 m^2. The solar fraction increases with the collector area up to 3000 m^2, although it seems to start flattening out over 7500-10000 m^2, which together with the diminishing specific yield for the same system sizes might explain the diminishing returns of increasing collector areas.

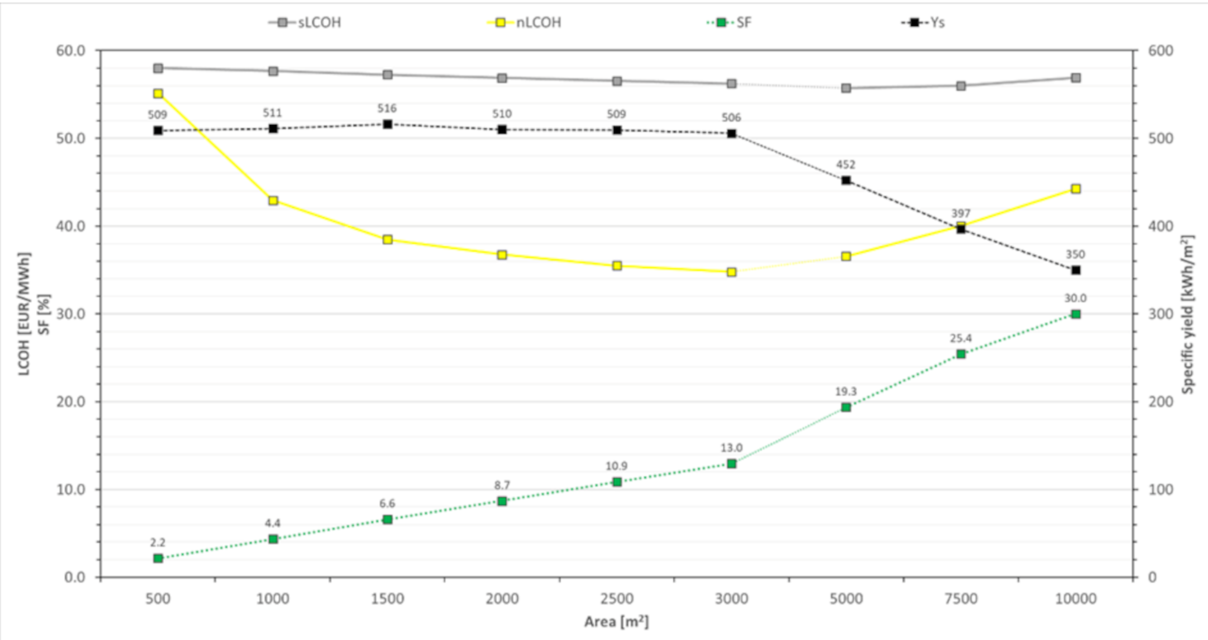


Figure 22: Solar system performance and heat cost – overview of sLCOH and nLCOH for solar district heating system variants 3 – 11, representing collector areas of 500 – 10000 m2, respectively. Abbreviations: solar fraction (SF), specific yield (Ys). Beware the non-linear x-axis in the figure.

The energy balance of the different variants will not be shown here, but is presented for variant 8 and 9 in *Paper IV*. According to the energy balance presented there for variant 8 and 9, with 3000 m^2 and 5000 m^2 installed collector areas, respectively, variant 9 shows lower boiler fuel use and higher collected solar energy compared to variant 8. However, the increase in collected solar energy in variant 9 is not proportional to the increase in collector area, negatively affecting the cost-efficiency of the solar heating system. This is reflected when evaluating the life cycle costs for variants 8 and 9, which despite lower boiler fuel use in variant 9, show that relative cost increase of storage and solar investment is higher than the increase in collected solar energy and this results in a higher nLCOH than for variant 8.

Summarising, the key findings indicate that:

- A smaller boiler with storage is cost-effective during re-powering, while different factors like emissions reductions play a role in deciding whether to adopt solar heating systems.
- Solar heating systems can be cost-effective in a retro-fitting scenario, providing up to one third reduction in unit heat cost with a relatively low solar fraction of 13%.

3.2.1.2 Solar assisted system with high temperature collectors

Table 13 shows an overview of the energy delivery to and from, energy performance and unit heat cost for a boiler with storage system (variant 2) and two solar assisted systems − one with 3000 m2 FPC (variant 8) installed and another with 3000 m2 ETC (variant 12) installed.

From the results, it can be noted that solar assisted systems with FPCs (variant 8) and ETCs (variant 12) are more cost-effective compared to a boiler with storage system. The sLCOH for both variant 8 and 12 is slightly lower than variant 2, but the nLCOH is significantly lower by 30% and 21% respectively. This indicates that FPCs are more cost-effective for retro-fitting a solar heating system than ETCs, the nLCOH being about 11% lower for variant 8 than variant 12.

Table 13: Overview major KPIs for variant 12 with 3000 m^2 of ETCs, compared to those of variant 8 with 3000 m^2 of FPCs and variant 2 with boiler and storage (see Table 7).

Variant	sLCOH [EUR/MWh]	nLCOH [EUR/MWh]	Q_FB [GWh]	Q_BE [GWh]	Q_sol [GWh]	SF [%]	Ys [kWh/m^2]
2	58.0	49.5	16.3	11.8	-	-	-
8	56.2	34.8	14.2	10.2	1.5	13	506
12	56.1	39.3	13.4	9.7	2.0	17	662

On the other side, the specific yield and solar fraction for variant 12 with ETCs (662 kWh/m^2, 17%) are higher than those of variant 8 with FPCs (506 kWh/m^2, 13%). This results in an 18% reduction in boiler fuel use compared to variant 2 and a 6% reduction compared to variant 8, indicating an enhanced match between district heating operating temperatures and ETC supply temperatures. Therefore, although the difference in sLCOH between variant 8 and 12 is minimal (less than 1%) due to the higher collector cost of ETCs, stakeholders may consider other factors like fuel and emission savings to make investment decisions beyond just cost-effectiveness. These results shows that while solar assisted systems provide significant cost savings and operational benefits compared to traditional boiler systems, stakeholders should weigh various factors beyond initial costs to make informed investment decisions.

3.2.2 Sensitivity analysis

The sensitivity analysis provided in *section 3.2.2.1* provides information on potential size limitations of the storage on solar heating system performance, while the analysis in *section 3.2.2.2* provides insight on the cost limitations of collector and biomass for solar heating to be cost-effective compared to a non-solar district heating system.

3.2.2.1 Storage volume sensitivity

Table 14 shows an overview of the unit heat costs (sLCOH/nLCOH), boiler fuel use (Q_BE) and delivered energy (Q_BE), delivered solar heat(Q_sol), solar fraction (SF) and specific yield (Ys) for three sub-variants 9.1 – 9.3 with 5000 m^2 collector area and variation of storage volume from 0.1 m^3/m^2 – 0.3 m^3/m^2 as presented in section 2.6.3. The table shows the impact of changing the storage volume on solar heating system performance and resulting unit heat cost, where the storage volume adapted for provision of *Paper IV* main results has been doubled and tripled.

Despite an 8% increase in specific yield for variant 9.3 with tripled storage volume, leading to an increase in the solar fraction (SF) from 19 to 21%, both the sLCOH and the nLCOH show an increase. However, the similarity in sLCOH values among sub-variants presented here and other variants studied in *Paper IV* (see Figure 21) hinders a clear conclusion on the economic significance of installing a larger tank during re-powering, although the nLCOH values rise considerably with increased storage volume. Retro-fitting with triple the specific storage volume as in variant 9.3, totalling 1600 m^3, results in a unit heat cost similar to that of variant 10 but with a significantly lower SF (21% in variant 9.3 vs. 25% in variant 10), indicating that when retrofitting, opting for a larger tank may not be cost-effective compared to expanding the solar heating system size. This is due to the higher monthly solar fraction from increased production, particularly in the spring, early summer, and autumn months, as evidenced by the monthly energy balances provided in Appendix B of the data repository belonging to *Paper IV [44]*. However, storage sizing is highly dependent on local conditions and thus, conducting a sensitivity study is crucial when sizing a solar heating system for district heating, and it should be repeated for every design iteration.

Table 14: Results for sensitivity study sub-variants 9.1 – 9.3 for a 5000 m2 collector area and storage volume of 0.1 m3/m2 – 0.3 m3/m2 as presented in Table 9. Abbreviations: St. vol. = Storage volume. KPIs explained in section 3.6.

Variant	St. vol. [m^3]	sLCOH [EUR/MWh]	nLCOH [EUR/MWh]	Q_FB [GWh]	Q_BE [GWh]	Q_sol [GWh]	SF [%]	Y_s [kWh/m^2]
9.1	600	55.7	36.5	13.0	9.4	2.3	19	452
9.2	1100	56.0	38.0	12.9	9.3	2.4	20	474
9.3	1600	56.1	39.7	12.7	9.2	2.4	21	486

3.2.2.2 Cost sensitivity

The cost sensitivity is analysed in two stages; One stage looking at how the discount rate affects the unit heat cost, i.e. at reference fuel cost and collector cost (see *section 2.6.4*) and another stage looking at the required collector cost for solar a solar assisted DH system to be cost-competitive with a non-solar assisted system, over a range of fuel costs and for three different discount rates.

Impact of discount rate on heat cost

This sub-section examines the impact of the discount rate on the heat cost for various solar district heating configurations. Figure 23 shows the variation in LCOH with change in discount rate (DR) for all variants simulated in *Paper IV*; selected values have been labelled, for example to show graph bottoms and peaks.

The following main points can be summarised from *Paper IV*:

- Trends from 3% discount rate remain consistent; The major trends observed for a 3% discount rate (see Ch. 3.2.1 and Figure 21) are generally maintained when the discount rate increases, with some exceptions.
- Cost-effectiveness of storage; Installing storage (variant 2) results in lower heat costs compared to a boiler-only system (variant 1) for all discount rates, both when re-powering and retro-fitting.
- Reduced cost-competitiveness of solar at higher discount rates; When retro-fitting, increasing the discount rate leads to reduced cost-competitiveness of solar heating, with a narrowing range of cost-effective collector areas.
- Cost-effective collector areas for re-powering; When re-powering at higher discount rates (5-7%), solar heating remains significantly more cost-effective compared to a boiler-only system, as long as the collector area does not exceed a certain threshold (7500 m^2 for 5% and 5000 m^2 for 7%).

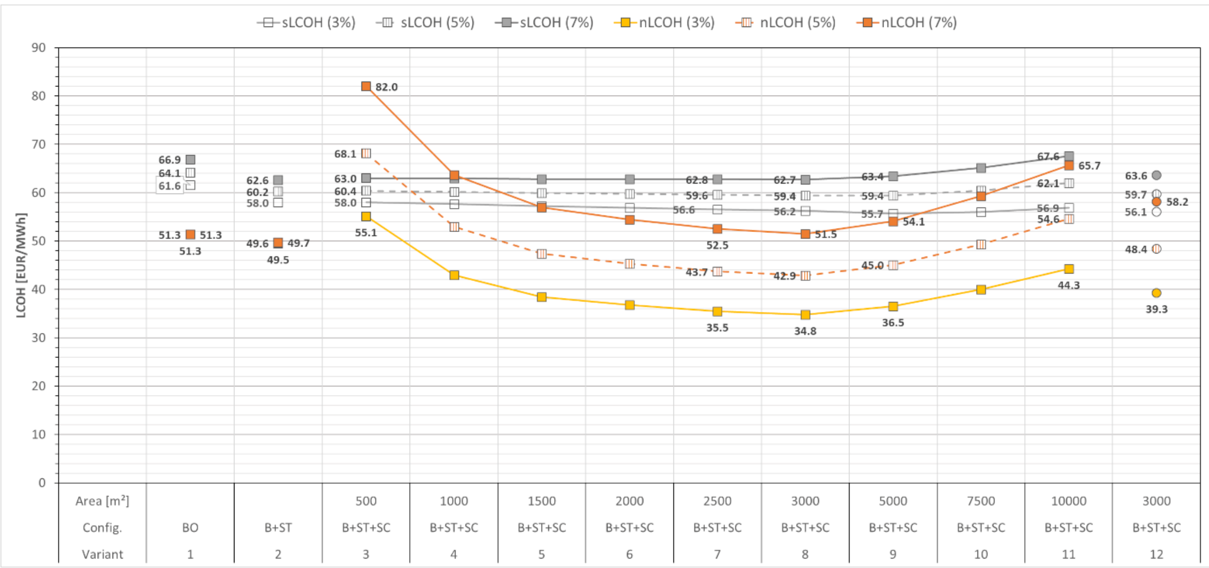


Figure 23: Cost variation – Change in LCOH for the simulated variants with discount rates of 3%, 5% and 7%.

Impact of discount rate on cost-competitiveness of solar heating

This sub-section examines the required solar collector cost to achieve parity in levelised cost of heat (LCOH) between solar-assisted and non-solar district heating systems for various (wood-pellet) fuel costs and discount rates.

Re-powering (boiler replacement)

Figure 24 displays the relationship between fuel costs (20 – 50 EUR/MWh) and collector costs at parity unit heat cost for a solar-assisted DH system and a non-solar DH system *when re-powering*, with discount rates of 3% (top solid line – brown), 5% (middle dashed line – orange), and 7% (bottom dashed line – yellow). Parity is achieved when the unit heat cost is the same for both systems. A solar-assisted system (here: variant 8 - 3000 m^2 FPC) becomes cost-effective compared to a non-solar system (here: variant 2 - boiler with storage) when the fuel cost is higher than 26.0 EUR/MWh at a discount rate of 5% with a reference collector cost of 240 EUR/m^2 (indicated in large green area). If the fuel cost is lower than 26.0 EUR/MWh at the reference collector cost of 240 EUR/m^2, a solar-assisted system is not cost-effective (indicated in small red area). Conversely, if the collector cost is lower than the reference cost at a fuel cost of 26.0 EUR/MWh, solar heating is cost-effective (indicated in small green area); if higher, it's not (indicated with large red area). In the case of the reference fuel cost being 31.4 EUR/MWh (see *section 2.6.4*), parity is already reached at a 5% discount rate, making solar heating more cost-effective than a non-solar system during *re-powering*.

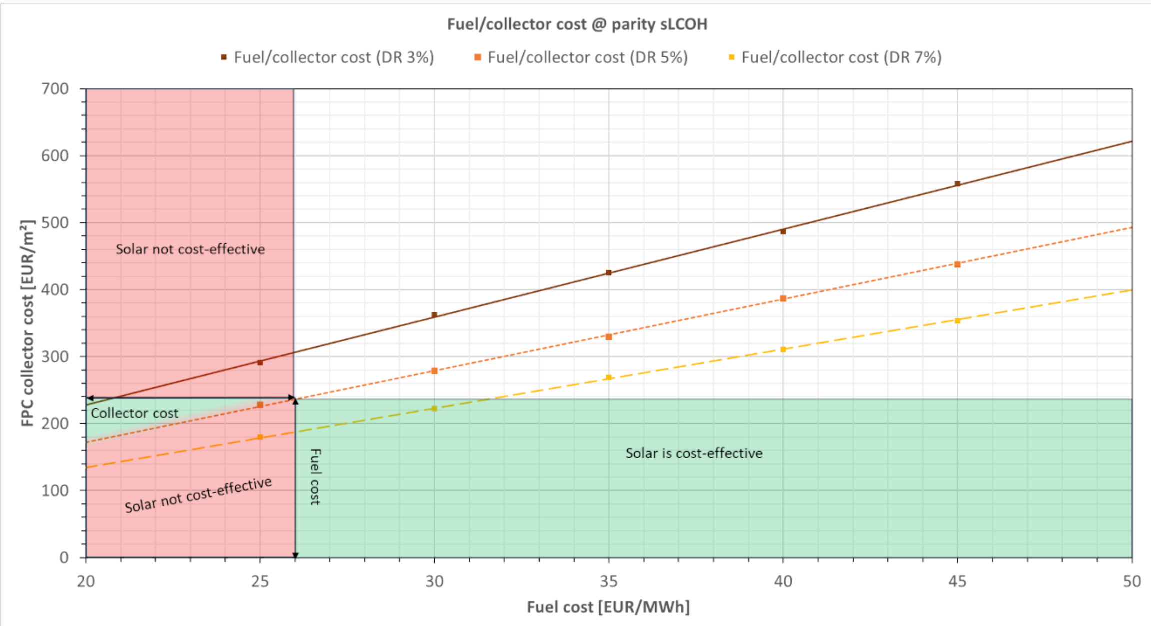


Figure 24: FPC cost at parity – Overview of corresponding fuel and collector costs when sLCOH (re-powering) is equal for a boiler with storage system (variant 2) and solar assisted system with 3000 m2 of FPCs (variant 8) for a discount rate of 3 % (top lines), 5 % (middle lines) and 7 % (bottom lines).

Figure 24 can be used to determine the fuel cost level that makes variant 8 more cost-effective than variant 2, for arbitrary choices of DR and collector cost, by drawing lines between collector cost on the y-axis, to the DR line of choice and, from the DR line to the fuel cost on the x-axis. If the fuel cost corresponding to a chosen collector cost is lower than the market price (here: reference cost of 31.4 EUR/MWh) of the fuel, variant 8 is more cost-effective than variant 2.

Similar graphs are available in Appendix B of *Paper IV* data repository [44] for the retrofit (nLCOH) alternative with FPC and for both re-powering/retro-fit alternatives using ETC. However, for simplicity, the fuel costs at parity sLCOH (re-powering)/nLCOH (retro-fitting) at reference collector cost level is presented in Table 15 for variant 8 and 12 and at different DR. The table shows the fuel costs required for different variants to achieve cost parity with a 3%, 5%, and 7% DR. Solar assisted DH becomes more cost-effective than conventional DH when fuel costs are above the listed thresholds.

For an FPC based system, solar is more cost-effective for re-powering when fuel costs exceed 21.0 EUR/MWh at a 3% DR and 26.0 EUR/MWh at a 5% DR. ETC based systems require fuel costs to be above 23.3 EUR/MWh at a 3% DR and 29.1 EUR/MWh at 5% DR for solar to be cost-effective. The reference fuel cost of 31.4 EUR/MWh is higher than all of these values, but lower than the values shown for a 7% DR, which indicates that solar is cost-efficient at low to moderate, but not higher DR. To remain competitive at higher DR, solar heating systems must have lower collector costs. Conversely, solar can compete at higher collector costs when fuel costs are higher, emphasising the importance of fuel prices in the cost-effectiveness of solar energy solutions.

Table 15 shows the required fuel costs for variant 8 (3000 m2 FPC) and 12 (3000 m2 ETC) to achieve the same sLCOH/nLCOH as variant 2.

Table 15: Fuel cost at parity sLCOH/nLCOH for variant 8/12 at three different discount rates (DR) and the reference collector cost levels assumed in this study

		DR 3%	**DR 5%**	**DR 7%**
	Fuel cost @ parity	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]
FPC	sLCOH	21.0	26.0	31.9
	nLCOH	20.9	26.6	32.7
ETC	sLCOH	23.3	29.1	35.3
	nLCOH	24.1	30.6	37.6

Retro-fit (existing boiler)

According to Table 15, for parity between nLCOH values of variant 2 and variant 8/12, the fuel cost threshold values are generally speaking slightly higher, which means that in the retro-fit scenario, the fuel costs must be higher than in the re-powering scenario, before solar assisted DH becomes more cost-effective than conventional DH (variant 2). Or said in another way, the collector cost must be lower than in the re-powering scenario for solar assisted DH to be cost-competitive with conventional DH when retro-fitting. This might come across as counter-intuitive, given the apparent cost-competitiveness of solar retro-fitting shown in Figure 21, but follows from how the system and net LCOH is calculated (see *section 2.5.3*) and where variant 2 benefits more from the combined investment and O&M costs being lower relative to the energy turn-over than in variant 8.

According to the results presented in this sub-section, the following concluding remarks can be made:

- Discount rate impact: As the discount rate increases, the required collector cost to achieve LCOH parity decreases, making solar heating less competitive with non-solar alternatives.
- Fuel cost impact: Higher fuel costs allow for higher collector costs while still maintaining LCOH parity, as solar heating becomes more attractive when fuel prices increase.
- Retro-fitting versus re-powering: The allowed collector cost to achieve LCOH parity is generally higher when re-powering compared to retro-fitting, as the costs relative to the energy turn-over makes solar assisted district heating more cost-competitive when re-powering[5].

3.2.2.3 Unit heat cost according to backup boiler fuel

Figure 25 shows the calculated sLCOH for all simulated variants in *Paper IV* when the July heat demand is covered by either an oil boiler or an electric boiler, normalised to the sLCOH when running with wood-pellets (WP) alone. The left y-axis show normalised values and the right y-axis shows the unit heat cost of running the WP boiler.

The results of the variation in backup boiler type and fuel suggests that solar heating can decrease fuel demand to such an extent that the choice of fuel type becomes less significant in terms of overall costs. This is due to the high solar fraction during the summer maintenance period (month of July), which despite high costs for fuels like oil and electricity, makes the impact of these costs small due to low boiler energy demand. This shows the benefit of re-powering and installing solar heating when the DH system has a fossil fuel based and/or high-cost backup-boiler installed.

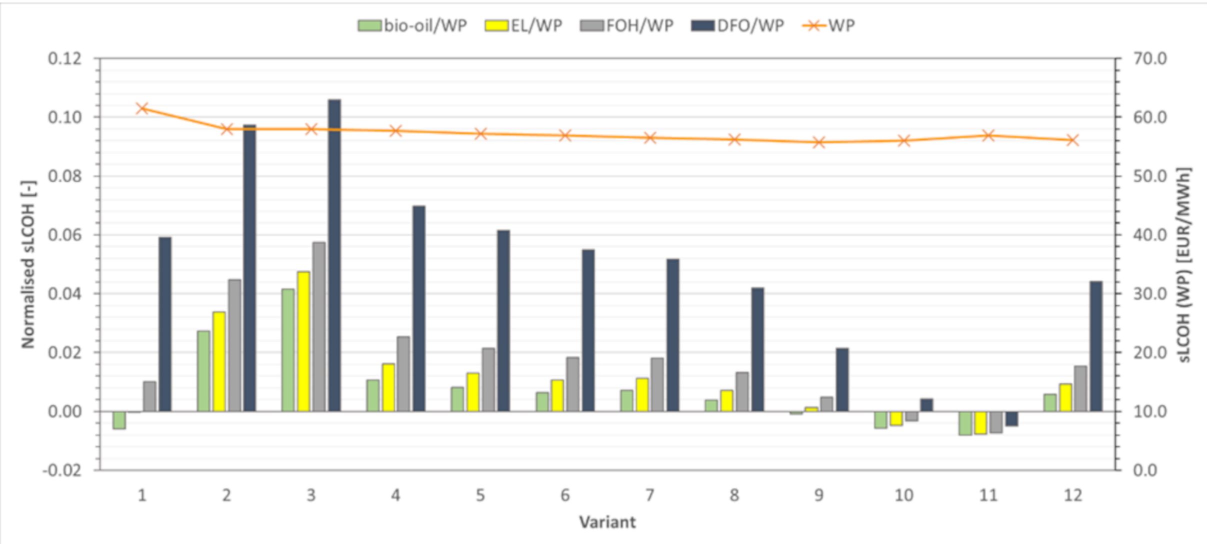


Figure 25: Alternative fuels – Overview of the unit heat cost when re-powering and employing various backup boiler fuels during maintenance of the main boiler during the month of July. Abbreviations: Electricity (EL), fuel oil – heavy (FOH), diesel fuel oil (DFO). Other abbreviations listed in nomenclature.

[5] Emphasis is put on the fact that this holds true when comparing variant 8/12 to variant 2, where a boiler in combination with storage yields a particularly cost-effective solution for increasing system performance. This conclusion is not necessarily valid for parity with a boiler-only system (variant 1).

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4. Discussion

The discussion is divided into three common parts for both the topic of new and existing district heating:

- The first discussion part related to each topic discusses the methodical approach and how this can influence the observed results.
- The second part discusses the employed boundary conditions and the influence on the results.
- The third and last part discusses the relevance of the results in the research field.

4.1 New district heating

This subchapter summarises the discussion points from **Paper II - III** that comprises the work on new DH and discusses the relevance of the results obtained in relation to the existing research conducted in the field.

4.1.1 Influence from methodological choices

This section summarises how the chosen modelling approach and cost calculation method affects the results.

4.1.1.1 Modelling approach

The impact of modelling approach has been covered extensively in the papers and therefore will not be covered in detail here. The reader is therefore referred to the papers for more elaborate information, although a summary of the main points is provided here:

- The modelling approach used in *Paper II* for district heating systems involved lumping components like heating load, substations, and pipe elements together, aiming to maintain specific temperature conditions. However, simplifications in the model could lead to inaccuracies in supply and network temperatures, potentially underestimating heat losses. This was evaluated in the licentiate thesis [1] and estimated to about 5% at worst, for a conventional DH system). As the pipe losses in the conventional DH system made out about 15% of the total energy turnover, the underestimation would influence the energy balance less than 1% and thus appears insignificant for the results in general.

- The selection of DHW profiles in *Paper II* was crucial as using a single-house profile for a larger housing area could exaggerate peak demands and underestimate draw-off frequency; while scaling down profiles might underestimate dynamic effects on solar. In this study, using DHW profiles based on the demand of 50 houses resulted in flatter load profiles and smaller coincidence factors compared to profiles based on 25 houses, which was deemed appropriate to arrive at a compromise between dynamic effects such as occasionally high solar yield and more consistent, but lower, solar yield (see *section 2.3.6*)

- The modelling of DHW load aimed at improving comparability and avoiding unrealistic system behaviours. The study's focus on total energy consumption rather than power minimised the impact of minor inaccuracies in solar yield estimations due to the chosen DHW profiles.

- Assumptions about acceptable pipe flow velocities, especially concerning material differences like PEX and steel pipes, played a significant role in pipe sizing and heat loss calculations in Paper III/IV. These assumptions could influence outcomes, with PEX pipes requiring one additional DN size for similar heat transfer capacity compared to steel pipes.

4.1.1.2 Cost calculation method

This sub-chapter aims to scrutinise the employed cost calculation methods and economic boundary conditions due to the relatively high impact of these on the results.

Different calculation methods in different papers

To recap, in **Paper II**, costs were collected from one manufacturer of steel pipe culverts and one of EPSPEX pipe culverts. Other costs, like those for trenching or substations were provided by HVAC consultants. The cost of connections, welding and VAT were not included and this level of detail was assumed appropriate in order to gain insight into the relative cost-effectiveness of the various distribution concepts against each other.

In **Paper III**, however, the aim to provide a more detailed and credible cost estimation made it necessary to include costs for connections and welding, in addition to more reliance on cooperation with the pipe manufacturers. Costs for trenching and other associated pipe work could be supplied from the former Swedish district heating association (Today: Swedenergy [45]) and were therefore reasonably accurate. On the other side, as the study included three various manufacturers (M1 – M3), this inherently involved some risks in terms of accuracy of pipe cost data. The pipe network pricing data used were obtained by liaising with the sales departments of the respective manufacturers. For M2 and M3, a network schematic and pipe size list were provided to sales representatives, who responded with tenders that included part specifications. For M1, a price list was provided alongside details of applicable discounts for steel and PEX pipes. The tender from M2 was used as a reference for selecting pipe components, such as joints and reducers, as these were comparable to the PI-PEX pipes from both manufacturers.

Two potential issues arise with this cost-gathering method:

1. The tenders provided by suppliers exclude vendor margins and may be below market price.
2. There is a possibility that tenders were undervalued as part of a market strategy.

While these issues may appear interlinked, they address slightly different concerns. The first pertains to the difficulty of determining how closely the tender aligns with actual market prices. The second relates to the chance that manufacturers, aware of the study's purpose, may have intentionally offered lower tenders than they would to a typical client.

Although these possibilities cannot be entirely ruled out, the small variations in pipe costs between manufacturers observed in the LCC analysis (see sub-chapter 3.1.3 and Figure 18) suggest that such practices are unlikely to have occurred. The similarity in costs also indicates that differences in pricing methods—such as M1's use of discounts versus direct tenders for M2 and M3—had minimal impact on overall pricing. It could be speculated that M1's application of discounts was part of a competitive market strategy, a hypothesis seemingly supported by *Paper III* findings. However, beyond conjecture, the minimal cost differences appear to reflect a healthy and competitive market. As a result, it seems unlikely that the aforementioned issues significantly influenced the outcomes.

Precision in cost calculations by software

The cost calculation software Wikells which was utilised in **Paper III** draws on a vast database of entrepreneurial costs from various projects and companies, producing estimates rather than exact figures. Professional users report that companies using the software often apply their own marginal costs to tenders, informed by past project experience. These adjustments can result in actual costs differing by as much as 20–30% for certain projects—a considerable variation. Consequently, the "standard cost" derived from the software serves more as a guideline than an accurate prediction.

The construction costs included in the study were based on real building designs, incorporating actual wall structures, HVAC systems, and electrical installations. The costs used were based on the average labour and material spending for construction as provided by the database, as explained in the previous paragraph. However, data from 2017 provided by one contractor involved in constructing an intermediate substation—similar to those modelled—revealed that the actual cost was 51% higher than the estimate provided by Wikells after inflation adjustments. This significant discrepancy appears largely attributable to HVAC installation materials and labour costs. Aligning Wikells' hourly (average) HVAC costs used in *Paper III* with the real hours worked would have increased the total substation cost by 44%, some 6%-points less than the actual cost, assuming all other Wikells costs remained unchanged. In other words, the costs used in *Paper III* for the intermediate substations (and possibly other construction elements) may be substantially underestimated.

Such substantial cost uncertainties inevitably raise questions about the reliability of cost analysis outcomes. That said, intermediate substation costs pertain only to the Hybrid concept, which has already been identified as the most expensive. Therefore, any additional cost would not alter the overall conclusions. While these uncertainties may prompt reconsideration of the apparent LCC differences between the concepts, even a 51% increase in the Hybrid system's ICC has a far greater effect on its LCC than on that of the GRUDIS system. As such, the observed difference in LCC between the distribution concepts is unlikely to decrease and may, in fact, become even more pronounced.

Changes in input variables

During the COVID-19 pandemic (2020 – 2023), financial stimulus measures were undertaken to keep the world economy stable despite decreasing productivity and consumption due to infection reduction actions. After the pandemic, these measures had the undesired consequence of increased inflation and this started exerting upward pressure on the costs of goods. This pressure was reinforced by the increase in interest rates by financial authorities worldwide. With the Russian invasion of Ukraine in 2022, the energy costs surged and added further upward pressure on costs for goods and services. Due to this, the results of **Paper II** and **Paper III** could be incorrect and this is discussed here by treating the impact of altering cost inputs.

Fuel costs

The fuel costs used for the LCC analysis in **Paper III** were sourced from statistics provided by the Swedish Energy Authority (Energimyndigheten) [39]. Data on the cost trends for refined and unrefined biomass fuels between 2011 and 2020 indicated a general decline from 2011 to 2017 (with the exception of 2016), followed by an increase from 2018 to 2020. The average refined (wood-pellet) fuel cost during this period was 282 SEK/MWh, with a range of 252–332 SEK/MWh. Year-to-year fluctuations in fuel prices, influenced by factors affecting supply, make it challenging to establish a single representative value. However, growing demand for biomass—driven by the shift towards renewable energy—is anticipated to exert upward pressure on prices at least until 2030 [17].

To account for this, the fuel cost selected for the analysis was based on the 2019 value of 305 SEK/MWh, which matched the 2011 figure before prices began their decline and is approximately 8% higher than the historical average. This choice introduces a margin for potential future price increases, with a sensitivity analysis exploring the effects of varying annual growth rates in fuel costs. While fuel cost does have a noticeable effect on the overall LCC and its components, it is small in terms of differences between the distribution concepts due to the relatively similar boiler fuel consumption across systems. As such, its impact on the comparative results is considered minimal.

Newer estimates foretell significant demand for biomass in the foreseeable future towards 2060 for use in bio-fuel production, where the willingness to pay for the biomass is even higher than today, exerting yet higher upward pressure on the price of biomass [46]. In the years following 2019, the fuel prices have continued upwards and the annual mean cost for 2023 was 475 SEK/MWh, which constitutes an increase of staggering 56%. The upward trajectory of fuel costs continued and the for 2024 the mean cost was 567 SEK/MWh, which constitutes an 86% increase to the cost employed in *Paper III*. Hence, the LCC would be significantly higher if the analysis was made today, although this would not change the conclusions drawn as the absolute costs increase in both distribution concepts. However, the relative difference between concepts would decrease a little, as an 86% increase in fuel cost would give a total marginal LCC of 20.3 M SEK for the GRUDIS concept and 25.1 M SEK for the Hybrid concept, reducing the relative difference from 24% to 19%. Regardless of this, solar heating becomes increasingly cost-effective as a means to replace biomass, as the fraction of operating costs used for biomass fuel increases from around 36% and 27% on average for the GRUDIS and Hybrid concepts, respectively to about 51% and 41%, respectively with the same fuel price increase of 86%. This should allow for even higher solar fractions depending on the cost-efficiency of the storage solution and/or distribution concept employed.

Component costs

The investigations carried out in *Paper II and Paper III* did not include costs for the solar heating system, as these were assumed the same for all distribution concepts. This of course is not entirely correct, as large centralised solar heating systems tend to cost less than those where the collectors are installed on roofs and the storage capacity is split into smaller units, as was the case in the Hybrid concept. According to the IEA task 52 on solar heat and energy economics in urban environments [47], the cost for a solar block heating system (typically 1000 m^2 collector area), with diurnal storage could be more than double of that for a large-scale centralised system (typically 10000 m^2 collector area), mostly due to economy of scale of the latter. However, seeing that the size of the FPC based part of the solar heating system in *Paper II* and *Paper III* a mere 620 m^2 and that this is the same for both GRUDIS and Hybrid, the likelihood of significant differences in system cost ready installed is small, even if the GRUDIS concept employs a more centralised solar heating system. The solar pipe costs are much (43%) larger in the GRUDIS system than in the Hybrid system, which supports this. And as stated, this would only be important, if the solar heating system costs were included, which they are not (only pipes are).

As explained in the introduction to this sub-chapter, the costs of goods and services have increased significantly in recent years. The component costs that were included in the cost analysis of mentioned papers, such as pipes and heat exchangers (*Paper II* and *III*) and construction costs related to material and labour (*Paper III*) have therefore likely also increased. Nonetheless, seeing that these cost increases would affect the total costs of all studied distribution concepts similarly, the results should still be valid. For *Paper II*, this means that the least costly distribution concept would still be All GRUDIS and that the focus of interest for *Paper III* would still include a comparison between this concept and the Hybrid concept. Due to the large cost difference between these concepts and the fact that the Hybrid system requires larger initial capital costs in terms of pipes and construction, the impact of increased costs would influence this system the most and thus, GRUDIS would still have the lowest LCC. Nonetheless, the collector costs have increased a lot over the last decade or so, which means that the cost competitiveness of solar vs. no solar is not as self-evident as before (discussed in *section 4.1.2.4).*

Financial costs

The sensitivity analysis made in *Paper III* on increasing fuel costs and interest rates showed that high interest rates impacted the costs for the Hybrid distribution concept the most. This is mostly due to the higher financial costs that follow from higher initial investment costs. As such, the high interest rates seen in world economy today would not lead to a different conclusion as to the most cost-effective concept, which would still be GRUDIS. Furthermore, as interest rates tend to fluctuate depending on inflation and monetary policies, it might be reasonable to view the results with a moderately high interest rate (i.e. 4% as in *Paper III*), considering that the economic lifetime employed when calculating the LCC was 20 years and that this would even out fluctuations over time.

4.1.2 Influence of distribution concept on system performance

This sub-chapter treats influence of assumed boundary conditions on observed results in **Paper II**. The observations are transferable and valid for *Paper III*, in regard to the Hybrid and GRUDIS concept.

4.1.2.1 System related operating conditions and solar performance

The energy balance in Figure 13 indicates that the solar yield in the conventional DH system is significantly lower compared to the hybrid and GRUDIS concepts. Table 16 summarises the performance of the flat plate collector (FPC) solar thermal system, including collector gains, pipe heat losses in the collector circuit, stored solar energy, and solar storage heat losses. The following observations can be made:

- Heat losses are greater in the conventional DH system compared to the alternatives.
- Collector gains are also lower in the conventional DH system.

In the hybrid and GRUDIS concepts, FPC arrays are connected to a storage tank used to prepare DHW. Cold water at an annual average temperature of 10°C is passed through internal coil heat exchangers, cooling the tank and creating more favourable conditions for the solar thermal system. Conversely, the conventional DH system operates with a minimum return temperature of 45°C, which limits cooling of the storage and reduces system efficiency.

Interestingly, despite differences in collector gains, the hybrid and GRUDIS systems store similar amounts of solar energy. This can be attributed to greater pipe heat losses in the GRUDIS system, caused by the longer solar culvert. Differences in storage losses may also reflect the variations in system configurations and operating temperatures between the concepts.

Solar fractions (SFs) further highlight these effects. The conventional system achieves an SF of 24%, aligning with the design value of 20% for diurnal storages reported in the literature (*section 1.2.1* and *1.2.2)*. However, the hybrid and GRUDIS systems achieve higher SFs of 31–32%, attributed to better cooling of the solar storage. This improvement results from system configurations and operating conditions, particularly lower storage temperatures, which enhance solar efficiency. Both the hybrid and GRUDIS systems can achieve these higher SFs, provided the GRUDIS concept is utilised for DHW preparation and distribution.

Table 16: Overview of FPC system performance, listing collector array gains, pipe heat losses, stored solar energy and storage losses in Paper II.

	Collector gain		Pipe heat loss		Stored energy		Storage heat loss	
	[MWh]	[GJ]	[MWh]	[GJ]	[MWh]	[GJ]	[MWh]	[GJ]
GRUDIS	240	863	36	129	204	734	45	161
Hybrid	228	822	23	82	206	740	63	227
Conventional	209	753	41	146	169	607	65	234

4.1.2.2 System configuration and net utilised solar energy

The solar fraction (SF) reflects the share of solar energy in the total energy input, while NUSE indicates how efficiently that energy is utilised. Although the hybrid and GRUDIS systems achieve similar SFs, their efficiency in using solar energy appears to differ. Figure 26 illustrates the calculated $NUSE_{SYS}$ (see KPIs in *section 2.7.1*) for the summer season (April to September) and annually, across all distribution concepts studied at varying linear heat densities (LDs). While the GRUDIS system appears to perform best overall, its annual NUSE remains negative. However, at 1 LD, both the Hybrid and GRUDIS systems show positive NUSE throughout the summer season, suggesting less reliance on the boiler during these months compared to the conventional DH system.

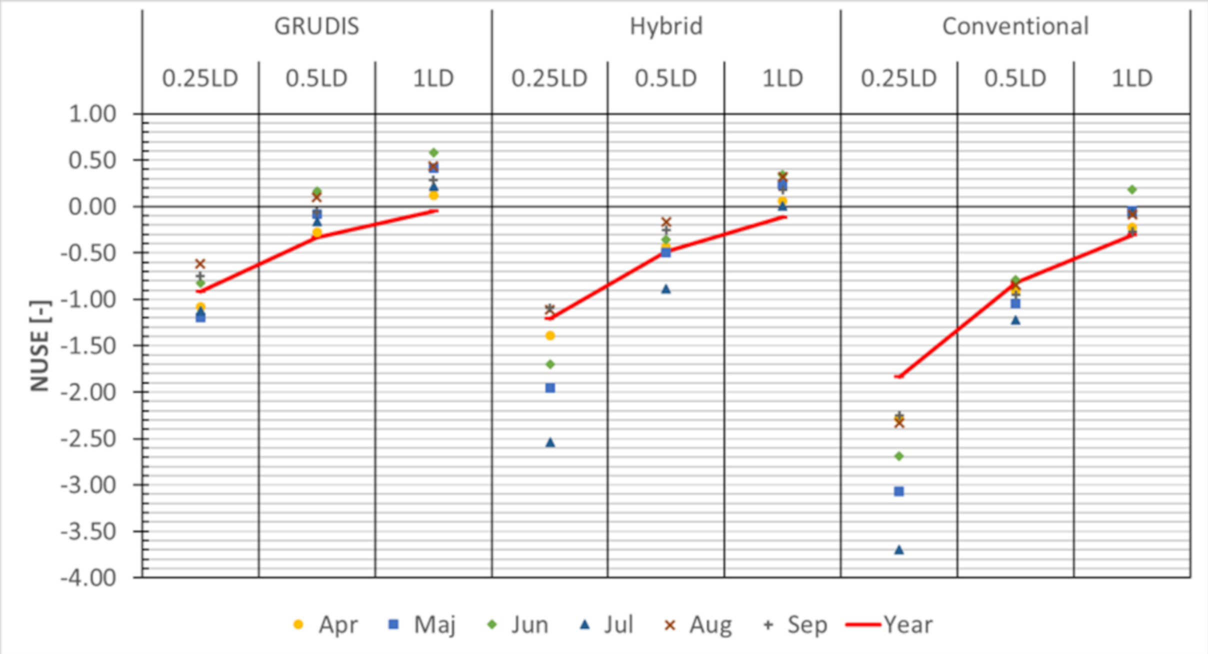

Figure 26: Plot showing the net utilised solar energy (NUSE) for the summer season (Apr. – Sep.) and annually, for three different line heat densities (LD) and all distribution concepts investigated in Paper II.

Although the hybrid system's NUSE comes close to that of GRUDIS, its summer values are slightly lower, suggesting reduced efficiency in solar energy use. In the GRUDIS system, stored solar energy appears to cover the entire network's heat loss, whereas in the hybrid concept, FPC-stored solar energy primarily serves the secondary network. This leaves the primary network's heat loss in the hybrid system reliant on ETC solar energy and boiler energy, potentially lowering overall NUSE.

In addition, the hybrid system's reduced discharge from FPC storage results in higher average storage temperatures, leading to increased storage heat loss (as shown in Table 14). Less frequent energy discharge also raises the likelihood of overheating in storage, which may account for the lower variation in summer NUSE values for the hybrid system. These findings could suggest that centralised storage and usage of solar energy might optimise its contribution, covering demand more effectively and improving NUSE.

When examining how NUSE develops with increasing linear heat density, the conventional DH concept shows the largest increase in annual NUSE values, while the GRUDIS system shows the smallest increase, with the hybrid concept falling in between. This trend aligns with the sensitivity analysis results, which highlight the relationship between the use of conventional steel pipes, higher operating temperatures, and greater distribution heat loss. The co-variation between heat density and heat loss is most pronounced in the conventional system, least evident in the GRUDIS system, and moderate in the hybrid system. These differences seem to reflect the interplay between system configurations, operating temperatures, and the ability to utilise solar energy for a larger share of overall heat demand, which is a defining factor in improving NUSE.

4.1.2.3 Substations and cost performance

The simple economic analysis presented in *section 3.1.2.1* is discussed here in more detail, to provide background for the conclusions made in *Paper II* and reasoning for the extended study in *Paper III*.

Looking to Table 12, if one were to add the pipe and trench costs only, the costs for the Hybrid (580 k EUR), All GRUDIS (590 k EUR) and conventional (570 k EUR) system would be similar. Based on this alone, the preference of either one would be particularly difficult, although the energy balance (Figure 12) shows that the boiler fuel cost would probably be too high for the conventional system. However, when including the costs for intermediate substations and house substations, the result becomes another one altogether. Including these costs shows that the GRUDIS system is the cheapest system overall, while the conventional system is the most expensive. This shows the importance of substations (or absence thereof) for the cost performance of the Hybrid and conventional distribution systems. The GRUDIS system which is configured with central DHW preparation benefits from a simple house substation with fewer heat exchangers and no intermediate substations, which reduces costs. Because the GRUDIS system also has the lowest boiler fuel use, this concept is likely to be superior in terms of life cycle cost compared to the two alternatives.

It is worth noting that the costs presented in Table 12 do not include costs of a larger BC to house additional storage for the centralised FPC solar heating system included in the GRUDIS/conventional DH system. Nevertheless, the difference in total costs (230 k EUR) between the GRUDIS and Hybrid systems is about the same as the cost of four intermediate substations (240 k EUR) and it appears unlikely that the construction of a slightly larger BC would have such high a marginal cost. Therefore, even when incorporating the cost of a larger BC, the GRUDIS system would probably be the most cost-effective. On the other side, due to the fact that the conventional system is the most expensive without the cost of a larger BC, it logically would also be the most expensive if additional construction cost were to be included.

4.1.2.4 Solar vs. non-solar district heating (paper extension)

One aspect that is not considered for new district heating and with *Paper III* in particular is that the cost analysis is based on marginal LCC costs and only compares two different distribution concepts on the premise of also using solar heating. It would have been informational and suitable to be able to compare the costs of solar district heating with conventional district heating using the same distribution concepts. In order to do that, it would have been necessary to provide a calculation for a system where the solar energy was substituted for boiler energy and to choose a cost performance indicator such as levelised cost of heat (LCOH). Only then could the cost performance be compared between a solar system and a non-solar system and the cost-competitiveness of using solar be evaluated properly and under varying economic conditions, such as in *Paper IV*. Unfortunately, lack of detailed costs for the Vallda Heberg system made the use of such an indicator unfeasible, which is why marginal LCC was chosen to measure cost performance.

Considering the marginal LCC provided in Figure 15 and that the solar fractions are similar in both distribution variants presented, the costs would probably be lower for a system where solar heating was omitted. This is supported by an adjusted LCC analysis (Table 17) where the heat demand is covered entirely by the boiler and the pipe and financial costs related to the solar heating system have been removed. Note that the storage volume employed has not been reduced, so the relative cost reduction may be slightly larger that it appears here.

Table 17 shows a comparison of the LCC in millions of SEK for the two reference variants in Paper III when the solar heat and associated costs have been removed:

Table 17: Cost comparison without solar – overview of the adjusted LCC of the two reference variants presented in Paper III when all heat is delivered by the boiler and solar related costs have been removed. *The total sum appears slightly incorrect when adding up part sums due to rounding errors.

Values in M SEK.	**G1 (ref.)**	**G1 (ref.) no solar**	**H1 (ref.)**	**H1 (ref.) no solar**
Financial	2.6	1.3	4.0	3.2
Boiler fuel	5.6	7.6	5.5	7.5
Maintenance	1.2	1.2	1.2	1.2
Construction	0.4	0.4	3.9	3.9
Distribution pipes	2.7	2.7	3.6	3.6
Solar pipes	3.0		2.1	
Total cost	15.5	13.3*	20.4*	19.4
Relative reduction		-14 %		-5 %

Note that the fuel costs were deduced by simply dividing the sum of original fuel costs over the 20-year lifetime of the LCC by the energy share delivered by the boiler (0.68 for GRUDIS and 0.69 for Hybrid). Therefore, the dynamic efficiency of the boiler which depends on load factor and its impact on fuel costs has not been taken into account, meaning that this is a crude approach to get an indication of the magnitude of the LCC difference between a solar and non-solar assisted DH system built anew.

Nonetheless, the total cost is reduced by 14% for the reference GRUDIS variant G1 and by 5% for the reference Hybrid variant H1, respectively, when compared to the costs in the LCC in Figure 15. Based on this, the Hybrid variant does not appear to gain significantly from omission of solar heating, although the GRUDIS system could. However, it is essential to remember that the fuel costs used in the original analysis were significantly lower than those found today, as discussed in *section 4.1.1.2/4.2.1.2* and, that with higher fuel costs, cutting out solar most likely would not yield the same cost benefits as shown here. Unfortunately, this cannot be determined conclusively without performing an updated analysis using current costs for all parts of the heating system and additional simulations that consider the detailed performance of the boiler, which is considered outside the scope of this thesis.

4.1.3 Relevance of results

The section on previous work outlined in **Paper II** and **Paper III** mentions some important knowledge gaps that are addressed in the papers;

Paper II

- **Storage Types**: Systems with short-term storage typically achieve design SF of ~20%, while long-term storage enables higher SF. <u>The paper challenges this notion.</u>
- **System Optimization**: Studies show that strategically placed short-term storage can increase SF, but more research is needed on decentral systems. <u>The paper confirms this.</u>
- **Distribution Systems**: Two-pipe systems with distributed storage are assumed cost-effective and to have lower heat losses. <u>The paper indicates that this may be true.</u>

Paper III

- **Plastic Pipes in DH Networks**:
  Studies highlight the cost efficiency of plastic (PEX) pipes, particularly in areas with low heat demand density. EPSPEX pipes, PEX encased in extruded polystyrene (EPS), show the lowest operating costs for such networks. The paper confirms that PEX is better than steel pipes for low heat density area.
- **Emerging Technologies**: PUR-insulated polyethylene (PE) pipes combine benefits of steel and PEX pipes, offering potential improvements for future low-temperature district heating (LTDH) systems. The paper confirms that these pipes provide cost-benefits.
- **GRUDIS Concept**: Uses PEX pipes and domestic hot water circulation (DHWC), providing simple installation and lower costs. Well-suited for low-temperature DH and sparse heat density areas. The paper confirms that this concept provides cost-benefits.

Collectively, the two papers show that the partial or complete integration of a plastic pipe network in a low-density DH system provides cost-benefits and have lower heat losses than its steel counterparts. If the plastic pipe network is integrated using the GRUDIS distribution concept, the solar yield is positively affected and costs are reduced as local DHW heat exchanger can be omitted. There is no particular difference in SF using central or distributed storages.

4.2 Existing district heating

This subchapter summarises the discussion points from **Paper IV** and discusses the relevance of the results obtained in relation to the existing research conducted in the field.

4.2.1 Influence from methodological choices

This section summarises how the chosen modelling approach and cost calculation method affects the results.

4.2.1.1 Modelling approach

The impact of modelling approach has been covered extensively in the paper and therefore will not be covered in detail here. The reader is therefore referred to the papers for more elaborate information, although a summary of the main points is provided here:

- The simulation model used in Paper IV simplified the representation of the solar collector and pipes by using one collector model for the entire area and one pipe element for a group of pipes, which may result in inaccuracies like not considering row distances and heat losses in pipes. These simplifications could lead to slight errors in harvested energy and pipe temperatures as they do not fully reflect reality.

- The use of one pipe element to model the entire pipe length may cause longer heating times for the solar loop and lower average temperatures in the pipes compared to reality. While heat losses from the pipes may be slightly underestimated in the model, the overall impact on the energy balance is minimal. Despite these simplifications being consistent across all variants, their influence on results is assumed to be insignificant.

List continues on the next page.

- Two minor simplifications mentioned are the absence of a minimum run-time for the boiler-only system and the use of theoretical U-values for storage. The lack of a minimum run-time for the boiler may result in unrealistic behaviour, but it is deemed appropriate due to the system's small thermal inertia. Similarly, theoretical U-values for storage might underestimate heat losses, but their impact on results is anticipated to be insignificant, as the largest fraction of storage losses make out about 0.4% of total supplied energy. This means even a five-fold increase in losses would render the results largely insignificant.

- The comparison between the annual irradiance of the reference year (2015) and an average year (2013–2022) showed a small difference of approximately 1%. This indicates that using weather data from either year is not expected to significantly alter the performance of the solar heating system. However, locations with different solar radiation levels and heat demands may yield varying outcomes.

- The high solar irradiation (in Gotland, Sweden) employed in Paper IV, influences the results. Locations with lower solar radiation and/or higher heat demands may find solar heating less cost-effective, leading to potentially different results.

4.2.1.2 Cost calculations

This section aims to reveal some effects of the cost inputs on economic results.

Costs for backup boiler

In *Paper IV*, the investment costs for the backup boiler were not included, which may affect the sLCOH for the various simulated system configurations. These costs were omitted partly due to challenges in obtaining them and partly because the choice of backup boiler in district heating (DH) systems depends on load considerations and fuel availability during system design. Additionally, it may not be necessary to replace the existing backup boiler, meaning its primary impact is the resulting fuel cost, as discussed in *Ch. 3.2.2.3*. Backup boilers often remain in service for many years due to their low running time. Therefore, the sLCOH results are valid under the assumption that the backup boiler is not replaced during re-powering and that all configurations use the same type of backup boiler, ensuring consistent comparisons.

Running the main biomass boiler with wood pellets (WP) during the one-month maintenance period in July, instead of using a smaller 1 MW backup boiler, is typically unrealistic, as the main boiler must be shut off for maintenance. This scenario suggests skipping summer maintenance, making the comparison of unit heat costs for WP and other fuels appear illogical. However, despite a significantly lower boiler efficiency and average part load ratio, the unit heat costs for the WP main boiler are lower than those for backup boilers and other fuels, which have higher efficiencies. If a backup boiler using WP were included, it would yield even lower unit heat costs due to a higher part load ratio and efficiency. This highlights the challenge of competing with biomass as an energy source at current prices, emphasising the need for greater valuation to encourage investments in renewables. Nonetheless, this would not significantly alter the results, as the competitiveness of backup boilers remains consistent.

The electricity cost (see *section 2.5.3*) in *Paper IV* was based on the annual average, which may overestimate unit heat costs for an electric backup boiler. In practice, electricity could be purchased at spot prices, which can be very low in summer. If the monthly average spot price were zero instead of the annual average (66.0 EUR/MWh), the total electricity cost would drop by 78%, from 84.8 EUR/MWh to just 18.8 EUR/MWh (the utility cost for a 1 MW electric boiler). This would make the electric boiler only slightly more cost-effective than an oil boiler using bio-oil, with a maximum difference of 3% for non-solar variants and less than 2% for solar variants. The minimal impact of electricity price is due to the relatively small share of annual energy demand met by the backup boiler. Thus, the presented results remain valid even with low or zero electricity costs.

Influence on results from boiler cost

For the boiler, it is assumed that investment costs increase linearly with the purchased capacity. This assumption is based on its use in other studies [48] and the uncertainty surrounding actual boiler costs. However, according to an industry representative from a boiler manufacturer [49], investment costs do not necessarily rise linearly; instead, they tend to decrease per unit cost [EUR/kW] as size increases, due to economies of scale (see Table 18). For a 3000 kW boiler, the assumed cost in this study is approximately 806 EUR/kW (see Table 10), while the manufacturer's estimate is around 427 EUR/kW, representing a reduction of about 47%. Although no cost was quoted for a 2500 kW boiler, linear interpolation suggests a cost of 485 EUR/kW, a reduction of about 40%.

Unfortunately, the manufacturer quoted costs only cover the boiler itself, excluding so-called balance of plant components, i.e. additional components (such as control systems) and installation, meaning the actual cost reduction from economies of scale is likely lower and varies by case. This was the main reason behind the choice of boiler costs to use in the economic analysis in *Paper IV*. However, although the quoted costs may not be entirely accurate, they serve to illustrate the potential cost benefits of larger systems, which is why they are brought up for discussion.

Nonetheless, while the differences between quoted cost and the cost employed in the economic analysis do not affect the nLCOH, as retrofitting excludes boiler investment costs, they do impact the sLCOH where these costs are included.

Despite the potential cost benefits due to economy of scale, the relatively small share of boiler investment costs in the total life cycle cost (LCC) of heat supply (see Fig. 9 in *Paper IV*) means that the sLCOH for a boiler-only system (variant 1) would decrease by about 8%, from 61.6 EUR/MWh (17.1 EUR/GJ) to 56.8 EUR/MWh (15.8 EUR/GJ), if calculated using the quoted cost instead of the assumed cost in this study. Again, this is excluding balance of plant components and associated costs. For the best-performing solar heating system (variant 8), the sLCOH would drop by about 6%, from 55.7 EUR/MWh (15.5 EUR/GJ) to 52.3 EUR/MWh (14.5 EUR/GJ). Although this would result in slightly lower sLCOH values and marginally higher competitiveness for the boiler-only system, the differences are small enough that the overall results remain valid. Thus, the findings are applicable even with a lower assumed boiler investment cost, except for a slight reduction in the difference between sLCOH and nLCOH.

Table 18: Quoted costs for a pellets boiler from a boiler manufacturer [49] **and presented in Paper IV.**

Size [kW]	**1000**	**2000**	**3000**	**4000**
Investment [EUR/kW]	789	542	427	357

The section continues on the next page.

Present day costs (paper extension)

As described in relation to the cost input variables (see *section 4.1.1.2*), the economic boundary conditions have significantly changed in recent years due to several reasons. The results presented in *Paper IV* were based on cost levels for the year 2021, which since have been far surpassed. This specifically involves fuel costs, component costs and financial costs.

In recent years, fuel costs have risen sharply, with wood-pellet prices increasing from 305 SEK/MWh (28.8 EUR/MWh) in 2019 to 475 SEK/MWh (41.4 EUR/MWh) in 2023 (a 56% rise) and reaching 567 SEK/MWh (49.6 EUR/MWh) for 2024 (an 86% increase). This escalation has significantly raised the operating costs and given that it would represent a permanent shift in overall cost level, would heavily influence the total LCC and thereby, the LCOH.

Component costs, including pipes, heat exchangers, and construction materials, have also risen, aside from collector costs. Recent studies indicate that the flat plate collector costs have increased a lot and are at 350 – 450 EUR/m^2 ex. VAT and ready installed with storage [50], for array sizes of 4001 – 10000 m^2 collector area. The cost in lower part of the range is for the largest array size and vice versa. For arrays of 4000 m^2 collector area and below, the collector costs are higher than 450 EUR/m^2. This represents an increase roughly of factor 1.5 – 2, which in itself could significantly reduce the cost-competitiveness of solar heating.

To further reinforce these severe cost increases, high interest rates have further increased financial costs, particularly for district heating systems with larger initial investments, such as those including a solar heating system.

All of the mentioned cost increases could potentially alter the perceived viability of solar heating for existing district heating systems compared to that which was presented in *Paper IV.*

In order to assess the impact of these cost increases, it would be valuable to evaluate Figure 24 yet again, although for other fuel and collector costs.

Figure 27 displays the relationship between fuel costs (20 – 50 EUR/MWh) and collector costs at parity unit heat cost for a solar-assisted DH system and a non-solar DH system with a discount rate of 7% (dashed line – yellow). The blue area indicates today's FPC cost range and corresponding fuel cost range (max, min and present day denoted). Parity is achieved when the unit heat cost is the same for both systems. A solar assisted system (here: variant 8 - 3000 m^2 FPC) becomes cost-effective compared to a non-solar system (here: variant 2 - boiler with storage) as long as the collector cost is lower than about 395 EUR/m^2 at the present day (2024) fuel cost of 49.6 EUR/MWh. If the collector cost is higher at the present-day fuel cost, solar is not cost-effective. Similarly, if at the present-day collector cost, fuel costs are lower than 49.6 EUR/MWh, solar is not cost-effective.

In Figure 27, the red areas have been added to show where solar *is not* cost-effective, next to the "FPC cost – max" and "Fuel cost – min". This means, that at "Fuel cost – max" (ca. 55.9 EUR/MWh), solar *is not* cost-effective when the FPC cost exceeds "FPC cost – max" (450 EUR/ m^2). Similarly, at "FPC cost min" (350 EUR/ m^2), solar *is not* cost-effective when the fuel cost is lower than "Fuel cost – min" (ca. 44.5 EUR/MWh). Correspondingly, the green areas have been added to show where solar *is* cost-effective, next to "Fuel cost – max" and between the graph and "FPC cost – min". This indicates that at "FPC cost – max" (450 EUR/ m^2), solar is cost-effective when the fuel cost exceeds "Fuel cost – max" (ca. 55.9 EUR/MWh). Similarly, solar is cost-effective when at "Fuel cost – min", the FPC cost is below "FPC cost – min" (350 EUR/ m^2).

In view of the results presented here, it is evident that a solar assisted DH system will continue to be more cost-effective than a non-solar DH system, given that the array size is sufficiently large. Looking at Figure 27, it is clear that at present-day fuel costs, the present-day FPC cost would have to be below ca. 395 EUR/m^2, which indicates a cost-effective solar heating system somewhere in the upper part of the range 4001 – 10000 m^2. This ties in well with the results from the *Paper IV* sensitivity study (*Paper IV* - Table 17), where it was shown that as discount rate and fuel cost increased, the most cost-competitive solar heating system size increased and was 5000 – 7500 m^2. *Thus, proposed method in Paper IV for determination of cost-competitiveness of solar has identified a collector cost that aligns well with expected collector costs today and has been validated by showing agreement with previously presented results in regard to system size.*

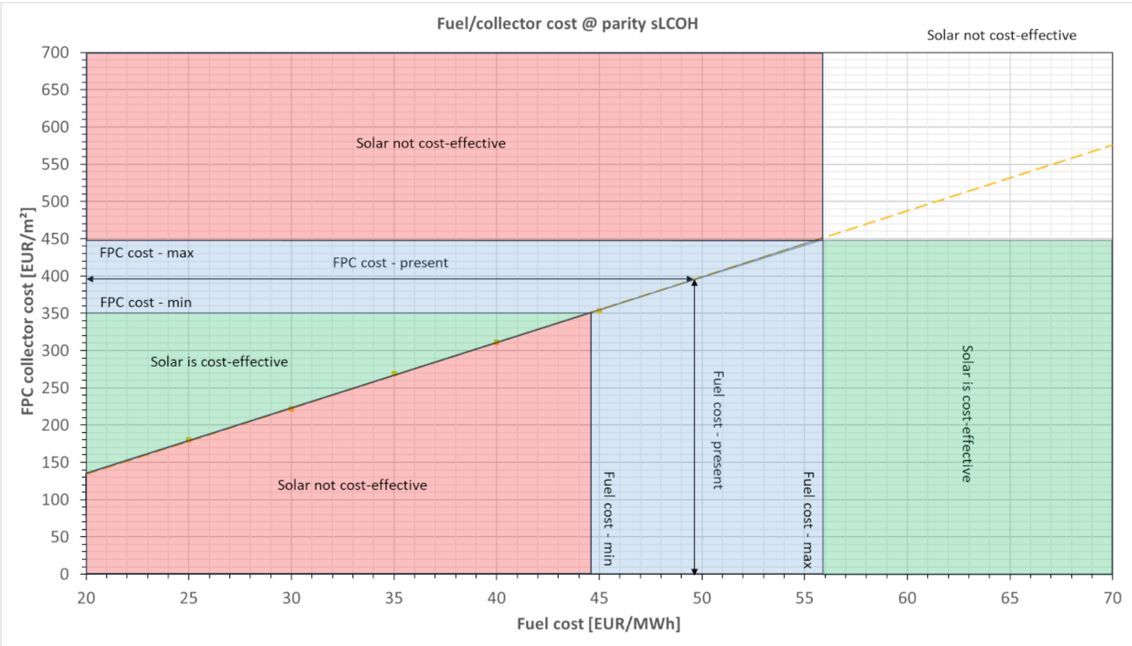

Figure 27: FPC cost at parity – Overview of corresponding fuel and FPC costs when sLCOH is equal for a boiler with storage system (variant 2) and solar assisted system with 3000 m2 of FPCs (variant 8) for a discount rate of 7 %. Present day (2024) fuel costs have been marked along with corresponding collector cost to reach parity unit heat cost.

4.2.2 Impact of reduced return temperature (paper extension)

When planning for installation of solar heating in a DH system, a natural measure is to investigate the possibilities of lowering the return temperatures in the network. Some positive effects from this are lower heat losses in the distribution network and increased efficiency for heating plants with exhaust gas condensation, which allows for lower production costs, although this is outside of the scope of *Paper IV* and this thesis. However, for a solar heating system this allows for increased performance of the solar collectors, which increases the solar fraction and may give lower unit heat costs for the solar energy.

Figure 28 shows a comparison of the specific yield and unit heat cost for a retro-fitted DH system for the case of the original return temperatures used in *Paper IV*, as well as for the case of a reduced return temperature by -5 and -10 degrees, respectively.

The following can be deduced from the figure:

- Lowering return temperature impacts the system similarly regardless of system size, increasing yield and lowering heat cost.
- The largest impact is seen for smaller system sizes, with decreasing impact above the optimal system size (3000 - 5000 m^2).
- The impact of lowering return temperature is linear, specific yield increases 1.2% per °C drop in return temperature, with a 6% increase for a 5-degree drop and 12% for a 10-degree drop.
- For each degree of temperature lowered, the nLCOH is reduced by approximately 1%. Hence on average 5% reduction for 5 degrees and 10% reduction for 10 degrees.

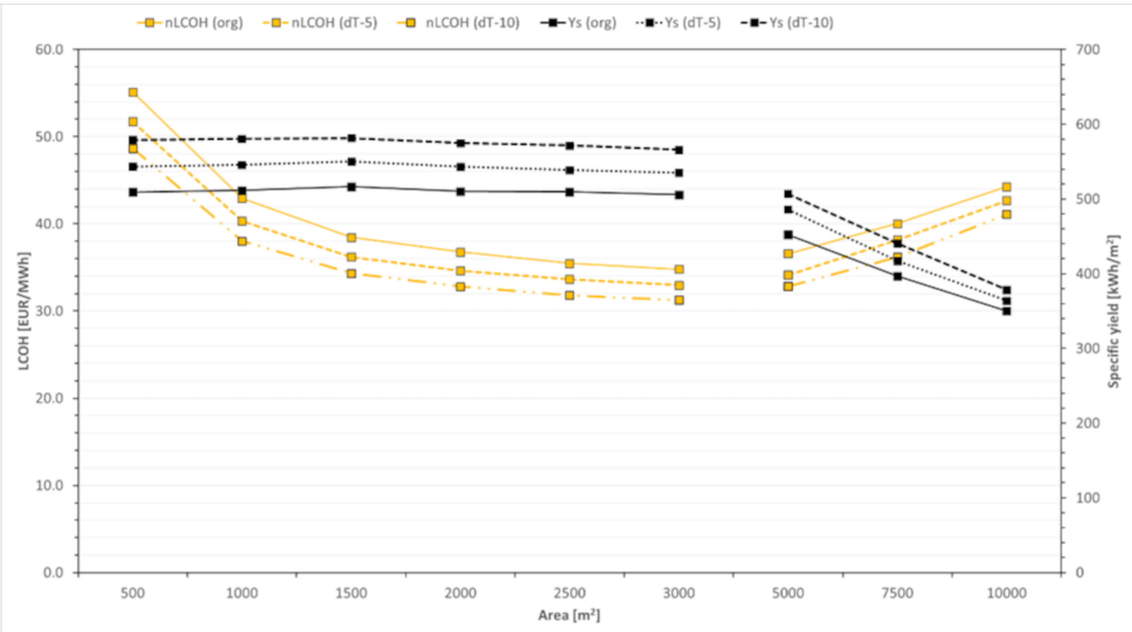

Figure 28: Lower return temperatures – comparison of specific yield (Ys) and unit heat cost (nLCOH) for a retro-fitted DH system using the original (org) return temperature as well as lower return temperature (dT) of -5/-10 degrees.

Subchapter continues on next page.

4.2.3 Relevance of results

The most relevant previous study related to *Paper IV* was conducted in Suonenjoki, Finland, and found that solar heating was not competitive with conventional wood-chip boilers. However, the current study challenges this conclusion by demonstrating that solar heating can be cost-efficient at lower interest rates, while still confirming that high interest rates make it less competitive – in line with the previous study. Additionally, *Paper IV* introduces a method to determine the economic conditions under which solar heating becomes viable and considers the impact of boiler replacement, unlike the previous study, which relied on an oil-based peak boiler throughout the year. Beyond this comparison, *Paper IV* also updates and expands on earlier research from 2008 on the cost-competitiveness of wood-pellet boilers, showing that solar heating can be a viable alternative.

Moreover, the findings confirm that flat-plate collectors (FPCs) remain more cost-effective than high-temperature collectors such as evacuated tube collectors (ETCs), highlighting the importance of investment costs for solar heating viability. The study also emphasises how high interest rates negatively impact solar heating competitiveness, underscoring the need for policy measures like subsidies to improve its feasibility against combustion-based and heat-pump alternatives. Given the increasing need for biomass to replace fossil fuel energy production and the strain on electricity grids due to electrification, direct heat sources like solar heating play a crucial role in the green transition. With biomass prices nearly doubling since 2021 and electricity costs expected to rise due to growing demand, this study provides valuable insights into the cost-competitiveness of solar heating compared to other district heating solutions.

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5. Conclusions

This chapter first provides a general summary of the work conducted and the main conclusions drawn from it. A more detailed statement of the conclusions for solar heating in new district heating systems is made in *Ch. 5.1* and for existing district heating systems in *Ch. 5.2*, with respect to the specific research questions investigated. Common conclusions are made finally in *Ch. 5.3*.

General summary

This thesis studies two aspects of solar district heating;

1. Provides a techno-economic analysis of optimal integration of solar heat into a new district heating system built from scratch and concludes on the most economic system configuration.

   Main conclusion:
   An All GRUDIS distribution system appears to be the best from an energetic point of view, and has the smallest life cycle cost.

2. Provides a techno-economic analysis of integration of solar heat into an existing district heating system and concludes on the required economic boundary conditions for profitable integration.

   Main conclusion:
   Solar heating appears cost-effective compared to non-solar heating when added to an existing district heating system.

Figure 29 shows an overview of the research development for the papers included in the thesis and the main conclusions arrived at for each paper.

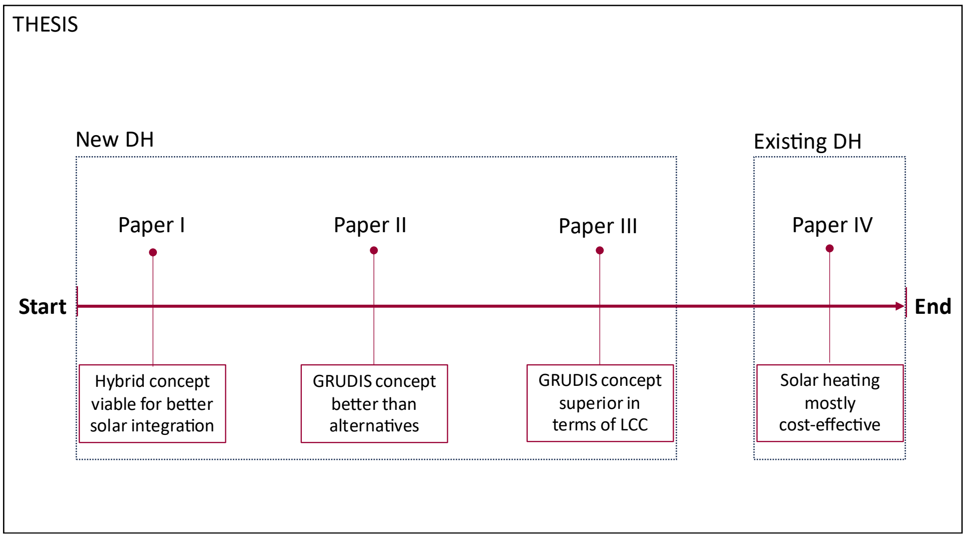

Figure 29: Research development – chronology of papers comprising the thesis along with main conclusions.

The main conclusions arrived at are explained in the following individual sub-sections related to each of the aspects studied.

New district heating

In Paper I, the literature on solar district heating was reviewed and a novel Hybrid distribution concept - combining a high-temperature steel-pipe primary network with a low-temperature PEX (GRUDIS) secondary network hydraulically separated by intermediate substations - was identified in the Vallda Heberg district heating system. **Paper II** then developed and calibrated detailed TRNSYS models of this Hybrid system and two alternatives - a conventional high-temperature steel network with centralised solar buffer stores and an all-GRUDIS low-temperature network - comparing their performance across varying linear heat densities and conducting a preliminary economic analysis. Finally, **Paper III** focused on the Hybrid and all-GRUDIS concepts, conducting a life-cycle cost assessment of eight hybrid and four GRUDIS variants featuring different pipe materials and insulation levels, together with sensitivity analyses of interest rates and fuel-price increase, to identify the most economically robust configuration.

<u>Conclusion summary</u>;

Paper I presented that improved solar integration is viable through use of a novel distribution concept that delivers promising results. *Paper II and III* show that the GRUDIS distribution system appears to be the best from an energetic point of view, due to high solar yields following low operating temperatures and the effective use of solar energy to cover distribution losses. Furthermore, the use of plastic pipes in district heating systems can provide a cost-benefit and lead to lower heat losses than using steel pipes. If the GRUDIS distribution concept is chosen, further cost-benefits can be had as well as better solar heating system performance.

The cost estimates used to calculate system costs were somewhat uncertain, although this is thought to be of less importance, as the GRUDIS system is the most cost-efficient nonetheless. This applies even in light of the large increases in cost seen in recent years, as a cost increase affects all distribution concepts similarly, *so that the GRUDIS distribution concept has the lowest LCC for a small solar district heating system built anew.* Furthermore, as the biomass costs are in an upward trend, this conclusion is expected to remain valid in the near future.

Future DH systems should therefore consider partial or complete use of plastic pipes as well as employing the GRUDIS concept.

Existing district heating

In Paper IV, an existing high-temperature district heating system due for boiler replacement was modelled across three supply configurations - boiler only; boiler plus storage; and boiler, storage and solar—where the solar option comprised eight flat-plate collector designs of varying size and one evacuated-tube variant, yielding twelve configurations assessed for cost-effectiveness both with and without boiler replacement. Two sensitivity analyses examined the impact of storage volume on solar system performance and the influence of economic boundary conditions - namely discount rates and fuel-price trajectories - on the viability of solar integration. This comprehensive study outlines the circumstances under which solar heat can cost-effectively reduce heat costs in high-temperature district heating networks.

Conclusion summary;

Paper IV shows that solar heating can be cost-competitive at lower interest rates, challenges previous findings, and introduces a method to assess its economic viability, including the impact of boiler replacement. It also confirms that flat-plate collectors (FPCs) are more cost-effective than evacuated tube collectors (ETCs) and highlights the need for subsidies, especially as rising biomass and electricity costs make solar heating a key solution for district heating in the green transition.

Whilst the chosen modelling approach may introduce slight inaccuracies in the simulated energy balance, its uniform effect across variants means the results remain realistic. The weather data, particularly irradiance, corresponds well with average conditions at the study site, making the findings representative—albeit not transferrable to regions with markedly different climates. Although the LCOH calculations may overlook backup-boiler investment and overestimate main boiler costs, this has little impact on the relative performance of the system variants. The study confirms that, when sized appropriately, solar-assisted district heating can compete on cost with conventional systems, underscores the value of low-cost flat-plate collectors and highlights the policy support needed to bolster solar heating's role in the shift to green energy.

The chapter continues on the next page.

5.1 New solar district heating

The conclusions provided below refer to the research objectives (RO) presented in *section 1.3.1*:

RO 1. *Determine the most suitable distribution concept for new district heating systems.*

i. A Hybrid distribution concept using a combination of conventional (3rd generation) district heating and a novel distribution concept called GRUDIS provides a viable way to successfully integrate solar heat into the energy supply of a district heating network built at the same time as a residential area, in an energetic and cost-effective manner (*Paper I*).
ii. A study (*Paper II*) on a small solar district heating system comparing three distribution concepts showed that the GRUDIS distribution concept was energetically and economically superior to alternatives such as a conventional or Hybrid distribution system, under the condition that the boiler central cost did not exceed the costs for intermediate substations in the Hybrid system.
iii. An elaborated study (*Paper III*) on a small solar district heating system comparing the GRUDIS and Hybrid distribution concepts, using different pipe technologies and detailed cost calculations, showed that GRUDIS had a significantly lower LCC.

RO 2. Evaluate range bound limitations in line heat density and insulation capacity for said concept.

i. A sensitivity study *(Paper II)* showed that the GRUDIS distribution concept was the energetically best distribution concept when line heat density was halved (very sparse DH) or quartered (extremely sparse DH).
ii. A parametric study (*Paper III*) showed that the GRUDIS and Hybrid system had a similar performance energetically, with minor variations due to the employed insulation level of the distribution pipes.
iii. A parametric study (*Paper III*) showed that while the average LCC of the GRUDIS concept was significantly lower than that for the Hybrid system, changing the insulation level did not significantly change the LCC for the Hybrid or GRUDIS concept individually.
iv. A sensitivity analysis (*Paper III*) showed that the GRUDIS concept remained economically better than the Hybrid concept when fuel costs and interest rates were increased.

RO 3. Identify cost implications of using said concept.

i. Comparison of three distribution concepts showed that the GRUDIS distribution concept was economically superior to alternatives such as a conventional or Hybrid distribution system, under the condition that the boiler central cost did not exceed the costs for intermediate substations in the Hybrid system (*Paper II*).
ii. Using a GRUDIS distribution concept was shown to reduce LCC by about 24% on average compared to using a Hybrid concept (*Paper III*).
iii. Additional conclusion (not a RO, but discussed in *section 4.1.2.3*); Absence of a more costly house substation (conventional DH) for both DHW and SH preparation or intermediate substation (Hybrid DH) makes the GRUDIS concept cost-effective (*Paper II)*.

5.2 Existing district heating with solar added retrospectively

The conclusions provided below refer to the research objectives (RO) presented in *section 1.3.2*:

RO 1. Investigate if solar thermal is cost-effective when added to an existing DH system with or without storage.

- Solar heating added retrospectively to an existing district heating system can be more *cost-effective* than non-solar district heating, given a sufficiently large solar heating system.

RO 2. Investigate if solar thermal is cost-effective when added to an existing DH system with or without storage, when boiler replacement is made simultaneously.

- Solar heating added retrospectively to an existing district heating system can be *cost-competitive* with non-solar district heating, when added together with a boiler replacement, given a sufficiently large solar heating system.

RO 3. Investigate the cost-competitiveness of ETCs vs. FPCs for above ROs.

- Using high-temperature evacuated tube collectors is not cost-competitive compared to using flat plate collectors.

RO 4. Investigate the cost-effectiveness of above ROs when changing collector costs, interest rates and/or fuel costs.

- Conclusions for RO 1 hold true under the condition that interest rates or collector costs aren't too high or fuel costs too low. However, the discussion shows that the results hold true even under present day conditions where both investment costs, operating costs and interest rates are very high.

  This conclusion was found in a sensitivity study providing a method to determine the conditions where unit heat costs for solar and non-solar district heating reach parity.

RO 5. Investigate how unit heat costs are affected by reduction in backup-boiler fuel use during summer maintenance of the main boiler, when installing solar together with a boiler replacement.

- Installing a solar heating system reduces backup-boiler fuel use and is cost-efficient regardless of boiler fuel type when the system size becomes sufficiently large.

RO 6. Investigate the impact of lower return temperatures on the techno-economic performance of the solar heating system.

- Specific yield increases by 1.2%, while the unit heat cost (nLCOH) drops by 1%, per °C drop in return temperature.

5.3 The common thread

Concluding, the results obtained in this thesis support that solar heating systems can be of benefit for both new and existing district heating systems. The timely supply of solar heat during parts of the year where the heat load is low and the relative distribution losses are rather high, significantly reduces fuel consumption and thereby, costs. However, it also improves resource efficiency, by enabling the use of the saved fuel elsewhere and, when the saved fuel is biomass, it has the potential to aid the green transition by replacing fossil fuels. Hence, the use of solar heat is of benefit not only to the district heating operator, but inarguably to the society as a whole, whether used in district heating systems built anew or added by means of retro-fit.

6. Future work

Based on knowledge gaps in relation to the studies presented in this thesis, and in relation to the field, I would like to make the below remarks regarding future work.

The future of GRUDIS

Even though the GRUDIS technology was developed during the expansion of the 3rd generation DH networks in the 80's, the technology has remained a peculiarity. It might be that the timing of its introduction was wrong, as it never seemed to gain the traction needed to reach large scale and international interest. However, with the transition to the 4th generation DH and low temperatures, GRUDIS seems to have a lot of characteristics that favour its implementation. Keeping in mind that one desired improvement in future DH systems was to remove recirculation flows and bypasses in order to acquire undisturbed return temperatures [14], GRUDIS both avoids circulating water in the buildings for local DHW preparation and has low operating temperature, which reduces heat losses. That said, for low temperature DH (LTDH) the technical configuration of the system is not necessarily given and therefore, future work should focus on how it could be realised technically when annual average return temperatures are $\leq 30^{\circ}$C. For such low return temperatures, GRUDIS is not applicable unless it includes the use of local heat pumps that can increase difference between supply and return temperature when covering SH, which could affect the cost-competitiveness greatly. Also, considering the technical limits of PEX pipes in terms of pressure, it is necessary to investigate the limits on network size when using these for entire networks. The studies included in this thesis give some pointers on the feasibility of using PEX pipe-based distribution for low density areas, but doesn't provide hard limits on network size. Studies on all of the above aspects are needed going forward.

However, as future improvements in DH system are mostly relevant for new systems and, although they may also be relevant for additions to existing systems, the addition of GRUDIS as a secondary network to primary networks in suburban areas should be investigated more closely. The majority of DH systems already exists and so, the use of GRUDIS to expand DH networks into suburban areas represents an opportunity to reduce heat loss and cost already today. Whether or not technical adaptations to LTDH may be utilised in these networks remains to be seen, although it is clear from the results in this study that such an expansion has important benefits that should not be disregarded. More studies are needed to demonstrate this. Furthermore, although some studies have been made on load side optimisation to lower return temperatures in existing DH networks, it is still unclear how large the potential reduction in heat loss is, aside from any benefits in terms of higher boiler and solar heating system efficiency. More studies should be made to determine the gap in costs between a conventional system with and without solar, akin to how it was done in *Paper IV*, when load side optimisation is made.

Economic modelling

Regarding economic aspects, the papers on new DH did not take into account the fuel use. The minimum turndown ratio of the boiler will lead to some fuel use that does not cover the demand or distribution losses, due to the different operating strategies in the Hybrid and All GRUDIS system. Therefore, more detailed studies are needed to model the additional fuel costs when regarding the minimum turndown ratio of the boiler and (the cost of) potential control strategies for mitigating this. An update of the study results using detailed boiler behaviour would be relevant, as would studies investigating control strategies for the solar heating system to assure maximum yield.

The work on existing DH (*Paper IV*) implemented the boiler efficiency and the estimated fuel use in calculation of unit heat costs, but it is still rather unclear how valid the simulated behaviour was. The will of a district heating operator to make investments in new heat configuration schemes could be hampered by perceived risk due to lack of credible results, effectively impeding the implementation of novel technology that is required for the green transition. So, validation studies are crucial to move the field in the right direction, as representative results are essential for credibility of results.

Furthermore, in terms of the boiler type employed, there should also be some studies where a wood-chip boiler is involved, as this is the predominant biomass boiler in Sweden. This would require study efforts that focus on thermal inertia of boiler performance and how this should be optimised with solar heat. Other relevant boiler configurations are related to sector coupling, which appears to be an increasingly popular topic in the district heating sector presently. The rising fuel costs in recent years have forced many operators to conduct feasibility studies and inventories that map energy flows in their heat supply and distribution, with the aim of increased recycling of residual heat. This often includes heat pumps and therefore naturally includes the dynamic effects of variation in electricity supply and the influence on operational costs this involves. A host of new questions are poised in this context, including whether or not the solar energy system should be thermal or photovoltaic, which adds another degree of freedom and hence, makes the research more demanding due to the share number of possible supply scenarios. So, a range of future studies are needed, where review articles may play an increasingly important role in order to steer the research effort efficiently and purposely.

Other economic aspects that are relevant for future studies are related to the use of EPS, both as additional insulation for conventional steel pipes and as insulation for PEX pipes. The use of EPS as additional insulation for steel pipes may represent an economic alternative in LTDH, as the costs of steel pipes are lower than those of PEX and have higher pressure limits that enable higher heat transfer capacities. Thus, the cost for use of EPS as additional insulation for steel pipes should be investigated for larger LTDH networks and compared to the use of pre-insulated pipes with a higher degree of (PUR) insulation and to the use of PEX pipes. However, this may require advanced analysis of the heat transfer and may involve the finite element method (FEM) or field measurements to be accurate.

Applicability to other locations

Lastly, it should be noted that the studies presented in this thesis are rather site specific and hence, somewhat lacking generality and perhaps applicability of results. The results found are applicable for sites with similar conditions in terms of irradiance, temperatures and urban environment. It is natural to think that the cost-competitiveness for solar assisted district heating is better in locations where temperatures and irradiance is higher, but this largely depends on the supply context, i.e. type of load and available resources, which makes it necessary to provide studies with a more nuanced approach to the specific supply context where solar heat holds the most promise. Further studies similar to those presented in this thesis should be conducted for other locations in order to find out how competitive solar heating can be when installed at locations with less solar radiation and/or other heat demand profiles.

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