Sustainable Heat Coalition

Helsinki Challenge Proposal

Team: SUSTAINABLE HEAT COALITION

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Terms / abbreviation	Clarification
Collector aperture area	Glazed (effective) area of a solar collector, smaller than gross area
CSH	Concentrated solar heat, a solar thermal technology
DH	District Heating
DHW	Domestic hot water
DR	Demand response
FTE	Full-time equivalent
FPC	Flat plate collector, a solar thermal technology
IDHP	Intelligent district heating platform
LCOH	the cost of producing heat including investment, maintenance, cost of capital, and depreciation of the investment, expressed in €/MWh.
PCM	Phase change material
SDH	Solar district heating
Single module	Single solar thermal plant with seasonal storage which generates 40 GWh of heat annually.

0. Overview of the proposed solution

This chapter first explains the proposed solution and its advantages in section 0.1. Then section 0.2 until 0.5 explains the different parts of the proposed solution.

0.1 General

Transition to a 100% renewable, decarbonised energy system is possible - even for cities exposed to cold Nordic climates. Through the ingenuity of six innovative European companies and their complementary technologies, Helsinki will be the first to showcase this with their district heating (DH) network. Our solution delivers 1039 GWh of CO_2 free, non-hazardous, cost competitive and environmentally friendly solar thermal energy per year while maintaining the existing level of indoor climate comfort.

The consortium brings five complementary technologies together in order to develop a systemic and scalable solution based on solar thermal energy that addresses the Helsinki challenge in technical, economical and sustainable dimensions. The proposed solution (depicted in figure 1) is a combination of systems consisting of large scale solar thermal plants, centralized seasonal heat storage, decentralized short term heat storage units, a real-time intelligent district heating platform, and a demand response program. By adopting these proposed measures, Helsinki will be able to reduce its DH network's CO_2 emissions by an impressive 78% by 2030 compared to current levels.

Our solution offers Helsinki to scale the produced amount of heat at their own implementation pace and adapt their supply needs according to their other remaining plans (Helen's indicative Replacement plans and others).

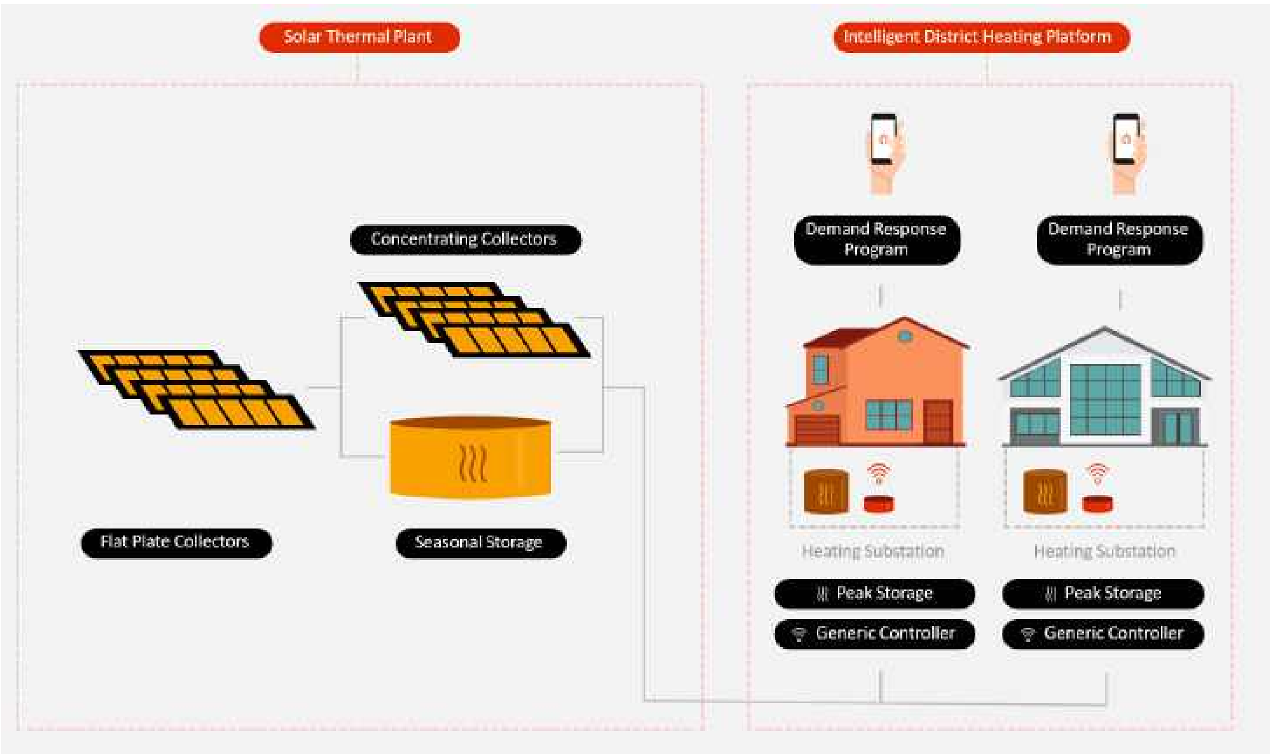


Figure 1- Visualization of the complete proposed solution

As a summary, we present the clear advantages offered with the proposed solution:

- The proposed solution is highly sustainable, cost competitive and technically feasible.
- It is scalable/modular for all parts of it, so the city of Helsinki can adapt the implementation plan to their needs.
- Our solution is not an "all eggs in one basket"-solution. Optimization is possible with other future plans such as: heat pumps, temperature levels, waste heat backbone from oil refinery, and other solutions from this challenge.

- Through this front-running project, Helsinki will serve as an example of sustainable urban heating for other cities worldwide with great CO_2 reduction potential.
- Helsinki will significantly decrease its import dependency on fossil fuels and provide a much higher degree of certainty for future operational costs.
- Solar thermal heat has a high social acceptance level, as demonstrated in many European countries.

0.2 Solar thermal plant

The solar thermal plant generates heat up to 95°C. This heat can be fed directly into the district heating network or it can be stored with our storage solution.

The 95°C are generated by two different solar thermal technologies:
- Flat plate collectors, which have long been used for heat generation in district heating systems around the world, heat the water to 70°C,
- then solar collectors that concentrate sunlight like large magnifying glasses do, heat the water to the targeted temperature.

The two solutions are combined because flat plate collectors lose their efficiency at higher temperatures, whereas concentrating collectors perform better at higher temperatures. The combination of using both technologies in series leads to higher efficiency in terms of cost, land use and fluid temperatures compared to using either of these technologies separately.

The full system is designed to supply 20% of Helsinki's annual heat demand by 2030 - in total 1,039 GWh - with no carbon emissions. Both collector technologies are well suited for being installed in modules adapted to the local need. This allows for building solar fields in modules close to where the specific heat demand is. I.e. the system can be installed at different locations in the perimeter of Helsinki. We estimate that if each module is designed to annually produce 40 GWh then no additional cost benefits will result from an increase in the module size.

The plants are an optimal combination of flat plate collector (FPC) technology from Savosolar and concentrated solar heat (CSH) technology from Heliac.

Savosolar has ten years of experience in solar thermal technology and systems. Its technology consists of large flat plate solar thermal collectors. This type of collectors (in Figure 2) is commonly used in large scale installations for district heating (the largest being 157,000 m^2 (in Denmark)) and industrial process heating globally. Such large systems are widely deployed in Denmark, Austria, Germany, France, Sweden, and outside Europe i.e. in China, Chile and Mexico. Some of these installations have been in operation for more than 20 years. In Finland, such systems have also been connected to district heating networks, although to date in relatively small scale (below 500 m^2).

Figure 2- Large scale flat plate collector field as part of a district heating network

Heliac has developed a novel method for concentrating sunlight (technology in Figure 3). Generating heat by concentrating sunlight is well-known but legacy solutions suffer from inherently high costs caused by their dependence on customized curved mirrors. Heliac's method is instead based on a low-cost method for high-speed production of transparent lenses that work like magnifying glasses. With this method their system can produce up to 350°C. In Helsinki, the temperature is limited to the 95°C that is required in Helsinki's district heating network. The collectors track the sun during the day. This makes it possible to have maximized heat production also during mornings and evenings, when the sun is low in its orbit.

Figure 3- Large scale concentrating collector field as part of a district heating network.

Different concentrating technologies are widely deployed globally when over 100°C temperature is required. Especially in industrial process heating they are used in growing numbers.

Flat plate collectors from Savosolar act as preheating solutions up to around 70°C depending on prevailing weather conditions. This heat is primed by Heliac concentrating collectors up to 95°C.

During cold winter days when higher temperatures than 95°C are required, priming will be done by Helen's existing gas boilers. The seasonal storage can be unloaded during peak demand hours and cold periods of the year with a supply power of 250 MW to the district heating network.

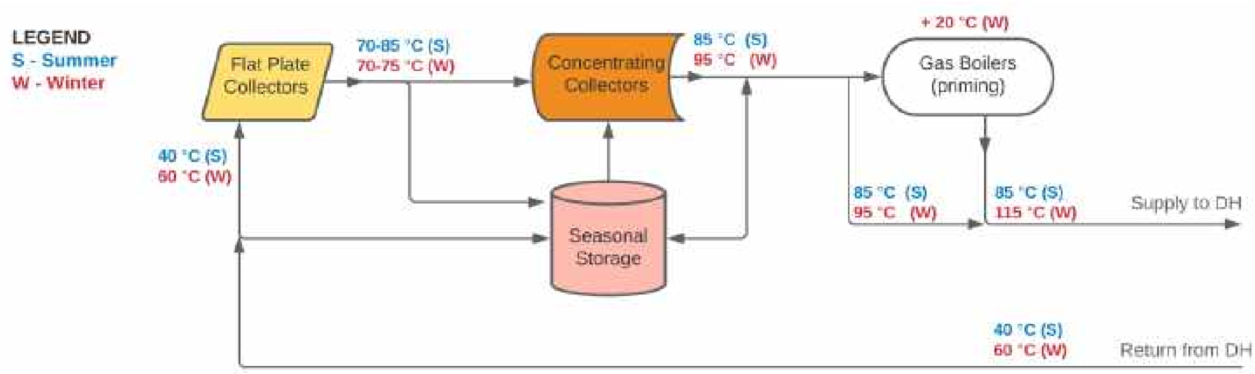


Figure 4- Schematic of solar thermal plants connected to seasonal storage (including the design temperature levels from the system to the district heating network)

The two solar thermal technologies are installed in the configuration as shown in figure 4, built on multiple solar fields of ca. 78,000 m^2 (called a single module) each, with a distribution of 55% of flat plate collectors and 45% of concentrating collectors. In total 27 modules need to be installed to achieve a heat production of

1073 GWh (which will result in 1039 GWh annually when accounting for 34 GWh in storage losses). The land area needed for each module and for the whole project is specified in table 1:

Table 1-Comparison for single modules and Full project targets

	Unit	Single Module	Total Project (27 Modules)
Target solar production	GWh/year	40	1,073 (1,039 after storage losses)
Area for collectors	m^2/aperture	78,600	2,108,000
Needed land area	m^2	172,800	4,638,000
Peak power for the solar thermal system	MW	53	1,435

The solar thermal system design is based on the following variables in Table 2:

Table 2-Solar thermal system design variables for the two different solar thermal technologies

System Design	Unit	Flat Plate Collectors	Concentrating Collectors
Collector production	kWh/m^2/year	506	513
Collector area needed to produce 1 MWh/year	m^2	1.98	1.95
Temperature increase	°C	30	25
Peak power - Single module	MW	33	20
Peak power - Full project	MW	886 (40/70°C, 25°C ambient)	549 (70/95°C, 25°C ambient)
Area for collectors per module	m^2/aperture	43,100	35,400
Fraction of production	%	55	45

0.3 Seasonal storage

To supply Helsinki with solar heat all year round, some of the heat produced during the summer months need to be stored for the darker and colder winter months. For this purpose a long-term seasonal heat-storage is provided by **Ecovat**. Each solar module has this seasonal storage integrated with the storage facility located near or under the solar field.

During summer, the solar fields charge the storage to 95°C. During wintertime the storage is discharged and the heat is supplied to Helen's network.

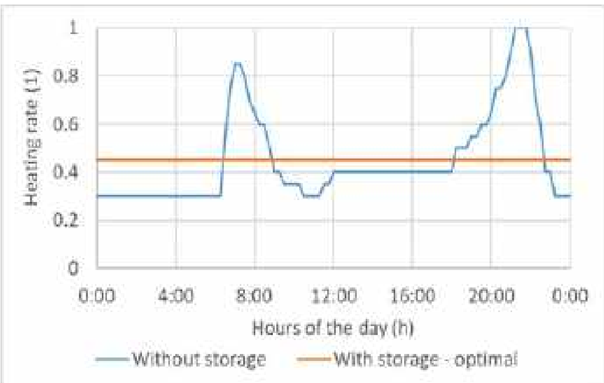
The storage solution is water-based in the form of a large underground buffer tank that has a minimum life expectancy of 50 years due to the concrete walls with high quality foamglass insulation. This insulation material can withstand high pressure and is water resistant. Because of this, the storage tank can store up to 95°C and the heat loss during storage period is only 10%.

The storage stores 33% of the total annual solar thermal production in order to provide the required flexibility. The production and storage balance is explained in more detail in chapter 6.1. The storage capacity for each single module is around 13,200 MWh and requires a volume of 206,400 m^3. When the total project size is implemented 1,073 GWh of solar heat is generated annually, and 354 GWh is stored annually. This requires a total storage volume of approximately 5.5 million m^3. The construction allows for the storage to be completely located underground, but also partially or completely above ground, depending on the hardness of the soil and the local building regulations. In figure 5, a possible integration in the landscape is shown.

Figure 5- Possible integration of storage tank. Underground is possible as well, depending on the soil conditions.

0.4 Peak storage

HeatVentors provides a decentralized and short-term heat storage which is charged and discharged on a daily basis. The decentralized heat storages add daily flexibility to the system, opening more possibilities to increase the share of renewable/waste sources and lower the share of carbon intensive peak sources. By installing these short- term storages a cumulative demand reduction of up to 8.9% can be realized.
The peak storages are based on novel phase change material (non-toxic, non-hazardous, no inflammable materials) and will be installed at substations level inside the buildings. These occupy 90% less space than the traditional water-based storages of the same capacity. Each tank is charged and discharged 2-3 times per day enabling them to function as a combined heat production unit of 162 MWh. or households with high domestic hot water needs, 2 cycles daily is standard, for restaurants 3 cycles, and up to 5 cycles for hotels.
On the following Figure 6 the peak reduction and added flexibility can be seen. The first graph represents a scenario, when DH provides a flat profile, showing that with the peak storage use, the demand from the DH network will be flattened. This is possible since the storage is charged when additional heat is available and discharged in peak time, meeting the needs of the DH network. This graph describes the winter operation- the operation mode during which no solar radiation occurs, or any other non-controlled heat sources are available.
The second graph presents the charging opportunity when excess thermal energy from solar is available. The peak storage can be directly charged from the solar source and discharged during peak demand periods. Following this idea, the share of solar, waste heat or any other non-dispatchable, but CO_2 friendly heat sources can be increased. This is the operation mode when solar radiation or other non-controllable sources are available.
For every specific end-user, the profile would be different depending on the size, location, usage of the building/substation. These two presented scenarios help to understand the basic concept and how the storages can contribute to the peak heat shaving/reduction.



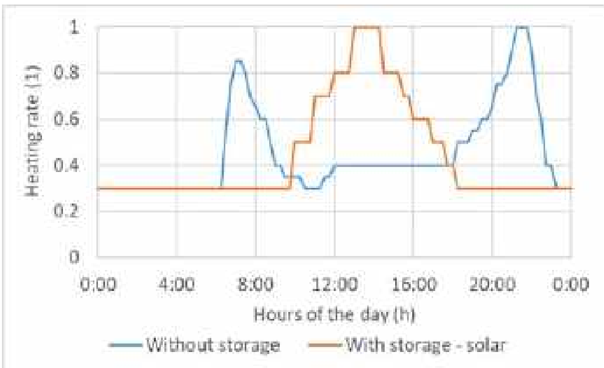


Figure 6- Two different scenarios of Peak storage units' effects on DH demand

The storage contains a patented control algorithm, to ensure efficient and intelligent operation. It is based on previous operations, measured data and future forecasts. The system runs on the software provided by ConnectPoint.

Operation of the peak storage units has a very low additional energy need as a result of 0,5-1% heat losses per day, and 5-20 W in additional pumping work. The peak storage units have a lifetime of more than 25 years.

0.5 Intelligent district heating platform

ConnectPoint provides two solutions (i) a digital optimization solution to smartly manage Helsinki's DH network assets and (ii) a Demand Response program (DR).

Intelligent District Heating Platform IDHP

The real-time - Intelligent District Heating Platform (IDHP) plays the role of a single data source for all the assets of the heat generation and distribution network. IDHP integrates into one information platform the new assets delivered in the project as well as the existing legacy SCADA/DCS solutions existing in Helen. The IDHP also contains analytical tools such as algorithms for optimal usage of sources and the forecast of future heat demand. The platform is powered by a self-learning model that optimizes the heating temperature delivered to the buildings in the network based on dynamic regulation of the heating substation parameters.

The district heating substations are connected to the IDHP through the plug and play generic controller of the ConnectPoint. Moreover, the internal and external temperature of the building is measured with temperature sensors. The generic controller measures both the primary heating circuit (district heating network) and the secondary heating circuit (the building itself); moreover, it allows Helen as an operator of the IDHP to steer the heating curves and operating parameters of the substations remotely.

Thanks to the possibility of remote optimization and diagnostics of heat substations, it is also possible to optimize their operation, reduce e.g., return temperature to the district heating network, transmission losses, and pumping costs. Furthermore, due to the possibility to steer the heat substations operation parameters remotely, it is also possible to use buildings' thermal accumulation and avoid the need to run costly peak sources.

Finally, the monitoring of the substations allows Helen to identify bottlenecks in the network or sections with over-capacity, which, in turn, contributes to more efficient operations and management. Features such as failure detection, control of operation parameters, visualization of substations, and prediction of the impact of parameter changes on energy consumption are available.

Behavioural Demand Response Program - DR

The behavioural demand response program (DR) tool is based on gamification, reward points, and the green heating index (GHI). By controlling the demand, it is possible to reduce the polluted fossil peaks during winter, balance the loads, and synchronize demand with the market. The DR system uses a single interface (mobile App) across all connected and intelligent devices (thermostats, smart plugs, air conditioners, etc.); allowing citizens to participate in DR programs for heating in the short term and electricity and district cooling networks in the future. Moreover, in the mobile application, the households will see the GHI for the current day, which shows the share of renewable sources in the current heating production mix per hour. The GHI will be calculated based on the forecast production of all the energy sources (renewable and non-renewable) and the correlation of the proposed storage solutions.

In the proposed DR program, citizens will create automatic routines to shift their thermostats and radiators' setpoint temperatures based on the GHI level. Since the target is to consume 100% green energy, the households will receive bonus points when lowering their setpoint temperatures when the GHI contains a high share of non-renewable energy. For instance, one family can create an automatic routine to decrease their setpoints in the living room by 1 or 2 °C when the GHI is lower than 80%. Thus, the Helsinki residents will be encouraged to consume heat produced by renewable sources which will be the cheapest heat source in the future after completing all the proposed investment activities.

To increase the adoption and engagement of the DR program and the connection of the substations to the IDHP, the following activities are proposed:

- The behavioural demand-response program will be gamified based. Moreover, the game's theme will be the Helsinki Challenge, whose primary goal is to close Helen's coal power plant. This program will engage with the citizens to actively provide their flexibility since 85%[1] of the residents are worried about climate change. Furthermore, to create social connection, the game will display a league table of the citizens participating in the DR events; households will be ranked according to their CO_2 reductions and contribution towards the city goal. Finally, families can exchange bonus points for discounts on Helen's smart home marketplace so that they can acquire more smart home devices.
- Besides the heat savings offered in the contracts (50% of savings - see cost impact section), every housing association will be equipped with an administration portal. The mentioned interface will allow association managers to allocate the heating costs based on the apartments' internal temperatures (real consumption). Moreover, the portal will display analytics and insights regarding consumption and energy savings. This portal will increase the housing communities' engagement because transparent billing of heating usage is one of the primary sources of complaints in residential buildings as per ConnectPoint experience.

Households can sign up for the DR program via Helen's website and book an appointment to install the smart thermostats and the temperature sensors. After the installation, users can pair their smart thermostats or radiators on the DR App and define the threshold upon which every thermostat will provide the flexibility. The DR algorithm will calculate the heating network's flexibility based on the users' routines and the GHI level. Even though the DR program is based on the GHI, if more flexibility is required, the system will send notifications to other citizens via the App and encourage them to participate in the upcoming events.

1. Climate impact

The current fuel mix in the DH system collectively has an estimated carbon footprint of ~2,095 ktCO_2/year, out of which 53% of CO_2 emissions are due to coal CHP plants. Our solution, complementing Helen's Indicative replacement plans (chapter 6), enables a CO_2 emission reduction of **78% in 2030 to 462 ktCO_2/year**, by:

- elimination of the Salmisaari B coal plant (equating to 605 kt CO_2/year emissions) by substituting this heat source with the carbon free solar thermal plants plus seasonal storage.
- a reduction of the gas-CHP utilisation and heat boilers (which equates to 116.5 kt CO_2 or an 19.5% reduction), partly by the adoption of the IDHP and peak storages (69.1 kt CO_2/year by 2030 by) as described in the following page.
- elimination of the Hanasaari B coal plant CO_2 emissions (equating to 868 kt CO_2/year emissions) by 2025, replaced by biomass, heat pumps and storages according to Helen's plans.

Furthermore, the proposed solution will have almost no impact on the carbon footprint of Helsinki's DH system, since the produced heat is generated from solar thermal and storage facilities, which are not directly carbon emitting sources.
Figure 7 below shows an overview of the reduction in CO_2 emissions in the whole DH system by 2030 (we considered a reduction in the emission factor due to the greener mix of heat generation):

[1] As per information provided during the Bootcamp

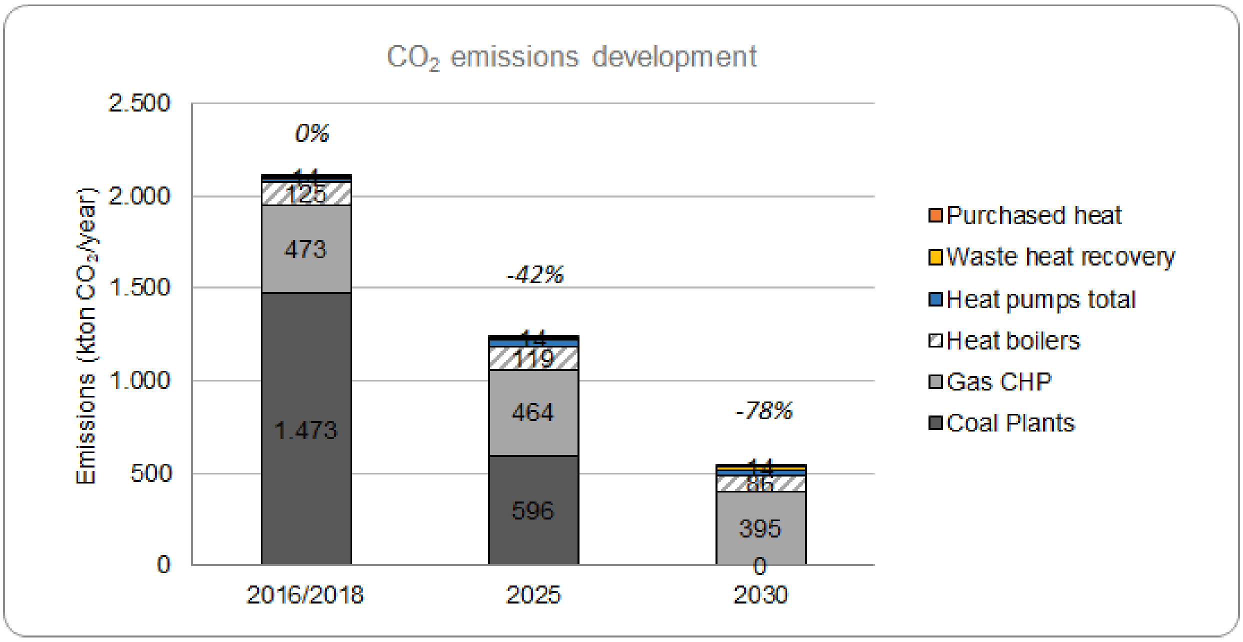


Figure 7-Annual CO_2 emissions for the DH system for current system, year 2025 and year 2030.

For the calculation of the CO_2 Emissions annually, the emission factors for the fuels used in the production of heat used were taken from Statistics Finland[2] and an emission factor of 30 $kgCO_2$/MWh for purchased electricity. Biomass is considered emission free in the context of this competition, as instructed by challenge organizers.

The cumulative demand reduction of the peak storages is 8.9% by 2030 (at least 20-50% peak reduction per substation where the storages are installed), which enabled significant CO_2 emission reduction by decreasing the use of Gas CHP and Heat Only boilers.

With the intelligent control due to the IDHP (digital platform), the Helen DH network will be able to reduce a total accumulated emissions of ca. 245 kton CO_2 by 2030. The carbon reductions are achieved thanks to optimizing the building substations and installing local control of the valves on radiators in apartments. Helen can achieve energy savings from 20 to 30% on average per building with the mentioned activities. For the estimations, we assumed an average savings for the building on the level of 8% and 12% in case of individual control in apartments. As a priority, the declining volume of heat production will reduce the heat generated from the most emitting sources based on gas and then on HOB. Furthermore, thanks to the implementation of the heat substations optimization and diagnostic system, it is possible to reduce the network's return temperature further, reducing heat transmission losses. Besides, by connecting buildings to the IDHP platform, it is possible to increase heat and electricity production sources' efficiency by adjusting the production to the future heat demand. The project assumes that district heating transmission losses will decrease by 0.6% and that production efficiency will increase by 0.5% within 10 years.

2. Impact on natural resources

Our solution is designed to replace the 300 MW CHP plant Salmisaari B. Solar thermal plants will be able to deliver an annual solar thermal heat of 1,039 GWh to the DH system requiring a cumulative land area of 4.6 km^2. The land areas needed for the collector field are rather large, but in the neighbourhood of Helsinki DH network there are plenty of areas which could be used without negative impacts to nature and scenery. In the proposed solution the flat plate collector fields produce lower than their maximum design temperatures maintaining high efficiency and reducing the capital expenditure (CAPEX) and the required land area.
The solar thermal plants are in this proposal planned to be installed in two locations (see below Figure 8); in the North-East of Helsinki and North-West of the city centre to balance the heat distribution into the district heating network. If there are space constraints, the Single Modules can easily be located also on more locations around Helsinki. A more detailed overview of the spatial distribution can be found in the attachment-section 2. These locations are chosen based on the principle closest area where the field can be installed without interfering with existing buildings and constructions, or areas where buildings are known to face public

[2] https://www.stat.fi/tup/khkinv/khkaasut_polttoaineluokitus.html

resistance.

Figure 8-Representation of proposed physical location of solar thermal plants at map scale for a better understanding of system size (wider image in attachment).

The seasonal storage is planned to be installed closely located to the solar thermal plants (to reduce losses) all at once or in modules. The cumulative volume of the seasonal storage is approximately 5.5 million m^3, occupying a surface area of 140,000 m^2 (or 0.14 km^2). The construction allows for the storage to be completely located underground, but also partially or completely above ground, depending on the hardness of the soil and the local building regulations.

One peak storage unit has 1.7 m^3 volume and requires 0.9 m^2 area. In one substation, 1-10 units can be installed together which means 0.9-9 m^2 space. It can be placed inside the HVAC room, on the roof or outside the building. The cumulative volume of 3,825 m^3 and an area of 2,025 m^2.
The peak storage reduces the daily peaks, which means an optimization opportunity for the heat sources.

In terms of energy resources, the gas boilers already existing in the Helsinki city infrastructure need to be used at the output of the seasonal storage and Heliac's collectors to raise the stored water fluid temperature from 95 to 115 °C, in case of hard winters. During summers, the gas boilers are not needed to top-up the solar thermal heat as the standard DH supply temperature can be achieved. The return of the district heating could be mixed in to reduce the supply temperature from 95 to 80 °C. The extra use of gas boilers would be compensated by reduction of the peaks using the peak storages but also the savings coming from the demand side management platform.

3. Cost Impact

This chapter first explains the total cost impact of all solutions including the annualized CAPEX and OPEX. Then the different solutions are addressed individually in more detail in separate sub-chapters.

3.1 General

The solution is suitable for step wise implementation, with no cost fluctuations depending upon scale of implementation.
An estimated CAPEX cost for the whole solution to cover the targeted heat demand of Helsinki City sums up to €932 MEUR. The breakdown (excluding interests and inflation) is:

- Flat plate and concentrating solar collectors €382 MEUR,
- Seasonal storage €415 MEUR
- Transportation pipeline €90 MEUR
- Decentralized heat storages €18 MEUR
- Digital platform €25.6 MEUR (including the IDHP Platform and behavioural demand-side management platform).

A cost of capital of 1% is used, based on multiple reasons: the loan costs are very low currently in EU with ranges between 0-2% WACC for projects based in Denmark and Finland; This is a CAPEX driven project, not dependent on annual price fluctuations of fuel costs, as is the case for LNG, coal or oil and e.g., caused by geopolitical issues; Renewable energy is mostly produced locally and therefore not as sensitive to geopolitics, nor to general price fluctuations. The annual operational cost (OPEX) of all technologies combined is approximately €52 MEUR for the whole project implementation until and including 2030. The breakdown of both CAPEX and OPEX by year is represented in Table 3 and a wider version is included in attachment (page 2).

Table 3- Annualized CAPEX and OPEX for all technologies implemented in the proposed solution.

Project/Contract Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2054
CAPEX												
Solar thermal (M€)	14.25	28.51	28.51	42.76	42.76	42.76	57.02	57.02	68.91	0.00	0.00	0.00
Seasonal Storage (M€)	0	0	0	77.40	46.44	46.44	46.44	61.92	61.92	74.84	0.00	0.00
Transportation pipeline (M€)	3.35	6.71	6.71	10.06	10.06	10.06	13.42	13.42	16.21	0.00	0.00	0.00
Peak Storage (M€)	0.40	0.80	0.80	4.00	4.00	8.00	0.00	0.00	0.00	0.00	0.00	0.00
IDHP (M€)	0.72	1.60	1.51	1.95	2.21	2.65	3.09	3.54	3.98	4.42	0.00	0.00
Total annual investments (excl interests) M€	18.73	37.62	37.52	136.17	105.47	109.92	119.97	135.89	151.02	79.26	0.00	0.00
TAI (incl. interests 1%)	18.92	38.00	37.90	137.53	106.53	111.02	121.17	137.25	152.53	80.05	0.00	0.00
TAI (incl. interests 1% and inflation)	19.29	39.53	40.22	148.87	117.62	125.02	139.18	160.81	182.29	97.58	0.00	0.00
Total cumulative investments M€	19.29	58.82	99.04	247.91	365.53	490.55	629.73	790.54	972.83	1,070.41	1,070.41	1,070.41
OPEX												
Solar thermal (M€)	0.00	0.11	0.34	0.56	0.90	1.24	1.58	2.03	2.48	3.02	3.02	3.02
Seasonal Storage (M€)	0.00	0.00	0.00	0.23	0.37	0.51	0.65	0.84	1.02	1.25	1.25	1.25
Transportation pipeline (M€)	0.00	0.07	0.20	0.33	0.53	0.73	0.92	1.19	1.45	1.77	1.77	1.77
Peak Storage (M€)	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02
IDHP (M€)	0.00	0.02	0.06	0.10	0.15	0.22	0.30	0.39	0.49	0.60	0.60	0.60
Extra costs for infrastructure												
Land Costs (M€)	0.69	1.38	1.38	2.07	2.07	2.07	2.77	2.77	3.34	0.00	0.00	0.00
Total OPEX (M€)	0.69	1.58	1.98	3.30	4.04	4.79	6.23	7.22	8.80	6.65	6.65	6.65
Total OPEX with inflation (M€)	0.71	1.65	2.10	3.56	4.46	5.39	7.16	8.46	10.51	8.11	8.27	13.05
Savings												
Income/savings from IDHP (M€)	0.00	0.48	1.11	1.89	2.84	3.92	5.16	6.54	8.08	9.78	9.78	9.78
Savings peak storage (M€)	0.09	0.27	0.45	1.35	2.25	4.05	4.05	4.05	4.05	4.05	4.05	4.05
Total Savings (M€)	0.09	0.75	1.56	3.24	5.09	7.97	9.21	10.59	12.13	13.83	13.83	13.83
Total Cost (real value) M€	977.89											
Levelized cost of Heat (€/MWh)		34.03	34.15	34.27	34.39	34.51	34.64	34.77	34.90	35.03	35.17	39.19

OPEX accounts for all maintenance, installation, pumping and personnel costs, included for all technologies, until 2054, and the reasoning is given in the following section. The only extra utility cost used for our solution is electricity which taxes are accounted for. Additionally, here, the cost of the transportation pipeline is included, representing around 9% of all CAPEX and which total value may vary depending on the local requirements for dimensioning of pipes, ground/soil type and costs per country.

Some of the extra costs represented in the table of annual investments, is the land area to be acquired. The cost for land needed for the collector field is approximately €18.55 MEUR, considering 4.64 km^2 and a price of 4 €/m^2. This cost of land is the team's estimate based on realized land purchases in Helsinki in past years. The savings per year are also represented in the table, with a breakdown for IDHP and Peak Storage.

For the total project lifetime (25 years), the CAPEX of €1,070 MEUR plus total OPEX of €303.85M (including interests and inflation 2%) result in a total project cost of €1,374 MEUR. This will be decreased by the total savings brought by the IDHP and Peak Storages (for project lifetime), to approximately **€978 MEUR.**

3.2 Solar thermal plant with seasonal storage costs

The solar thermal plants together with seasonal storage represent the majority of CAPEX for the project, cost calculations are explained in the following section. One of the aims of this dimensioning and chosen assumptions was to reach a competitive Levelized Cost of Heat (LCOH) delivered to the DH network. The total Levelized Cost of Heat can be calculated as the sum of the cost per MWh of all technologies contributing to the production of heat, over their lifetime in order to compare different designs and technological solutions with one another.

The resulting LCOH of 33.80 €/MWh is within the same range as biomass (25 -35 €/MWh for woodchip and pellet prices). This production cost is still under the current average district heating retail heat price of 47,91 €/MWh (VAT 0%), offered by Helen which makes it cost competitive towards the end user, increasing the social acceptability. In Table 4, the LCOH is broken down in three parts: solar thermal, seasonal storage, and transport. These parts are explained in more detail below. The development per year of this LCOH is shown in Table 3 and considers inflation rates.

Table 4-Calculated Levelized Cost of Heat for Solar thermal, Storage and Transport

Technologies	LCOH (€/MWh)
Solar thermal	18.85
Seasonal storage	11.21
Transport	3.74
Total	**33.80**

For solar thermal collectors, the total investment period considered is 25 years as this is the standard lifetime for solar thermal technology. The system costs for suppliers 1 and 2 - flat plate and concentrating collectors are shown in the table below, plus a third column with the joint solar plant cost.

Table 5- System costs for solar thermal suppliers

Solar Thermal Plants Costs	Unit	Flat Plate Collectors	Concentrating Collectors	Total
Investment price per production	€/MWh	375	333	-
O&M	€/MWh	1	5	-
Price per MWh for investment time	€/MWh	16	18.3	18.85 [1]
System m^2-price	€/m^2	190	171	-
Total system price for one module	M€	8.2	6.1	14.3
Interest - Capital cost 1%	€/year	40,965	30,305	71,270
Total system price for Full Project	**M€**	**219.843**	**162.632**	**382.475**

[1]- Weighted price per MWh for investment time (€/MWh)

For seasonal storage the costs are presented in Table 6.

Table 6- Cost variables for Seasonal Storage

	Unit	Single Module	Complete Project (27 modules)
Heat production from solar thermal	GWh	40	1,073
Required storage share	%	33%	
Required storage capacity	GWh	13	354
Required storage volume	m^3	206,400	5,538,700
Investment per m^3	€/m^3	75	
Total investment	M€	15.5	415.4
Minimum life expectancy	years	50	
Investment per MWh	€	7.74	7.74
Cost of capital per year	M€/year	0.08	2.08
Maintenance per year	M€/year	0.05	1.25
Total cost seasonal storage per year	M€/year	0.43	11.63
Total cost seasonal storage per MWh	**€/MWh**	**11.21**	**11.21**

The LCOH for solar + storage is 18.85 + 11.21 €/MWh = 29.54 €/MWh.

For transporting all the solar thermal heat from the plants and seasonal storage to/from the DH network, a new pipeline needs to be installed, with a calculated approximated length of 10 km in total. For this calculation we assume that all solar thermal heat plants are connected to this pipeline. For this, a DN 700 pipeline is needed. The assumed approximate cost per meter is 9000 €/m (based on a similar project in the Netherlands, which has a cost of 6000 €/m (see [3]), however, no standard cost was found for Finland). Well-maintained DH networks last for at least 50 years and is therefore used as the assumed lifetime[4].

Table 7- Cost variables for Transport of Heat infrastructure

	Unit	Single Module	Complete Project
Investment heat transportation infrastructure	M€	3.4	90
Investment cost per year	k€/year	67.1	1,800
Interest	k€/year	16.7	450
Maintenance	k€/year	33.5	900
Pumping costs	k€/year	32.4	869
Total costs	k€/year	149.8	4,019
Cost transport per MWh	**€/MWh**	**3.74**	**3.74**

3.3 Peak storage

For the peak storage units, the cost is 8000 €/unit, including installation. These storage units will be installed at substation level, and the installations are performed yearly from 2021 to 2026. The CAPEX and OPEX are represented in the total costs table.

CAPEX costs include the design of the system, the storage units, the PCM, shipping and installation with all system components, balancing valves, etc.

The peak storage units do not incur any significant fixed operating costs since there is no need for maintenance as there are no moving parts, so OPEX is minimal and represented in heat losses (0.5-1% per day) and the maximum of 5-20 Watt of additional pumping work.

An average 1800 €/installed peak storage can be realized as savings due to various factors. By providing heating when the peak needs occur, less power is required from the district heating network which results in:

- lowering the pumping power requirements by up to 12% per day for the substations where peak storage units are installed, results in the 17-26% of savings (300-470 €/year, depending on the size, location, and usage of the substation),
- lowering the transition heat losses, which accounts for 22-34% of savings (400-610 €/year),
- lowering the heat losses in comparison to water-based buffer storage units by up to 45% as the phase change material (PCM) technology offers smaller storage sizes and higher energy efficiency - water storage units are usually in "C" or "D" energy class, but the PCM based peak storage can reach class "A+" thanks to the compact size and the fact that when the PCM storage loses heat, part of the PCM solidifies to the wall of the storage increasing the insulation of the storage, 26-32% of savings (470-580 €/year),
- by decreasing the share of high-cost and CO_2 intensive peak heat sources not just CO_2 saving can be achieved, but the levelized cost of heat is also decreased, 8-12% of savings (145-220 €/year),
- 4,2-5,1 ton CO_2 avoided emission also accounts for a saving factor combining the above-described reasons, 8-9% of savings (145-160 €/year), of which 12% is generated by the electricity savings thanks to the reduced pumping power, and 88% is generated by the heat savings.

It is possible to completely disconnect substations from the district heating network, substantially reducing the heat transition losses, and to provide heating and domestic hot water from the peak storage units (taken into account at the heat transition losses above).

As the peak storage is a completely indirect heat storage facility, the growth of legionella or other bacteria is not considered an issue as it functions as a "flow-through" gas boiler for DHW production. Infections and contamination are frequent in water buffer tanks, bacteria can appear in the large stagnant water. However, no cost has been included here for sterilization or water treatment, which can cost 150 €/year, excluding the

[3] www.warmteling.nl

[4] https://energia.fi/en/energy_sector_in_finland/energy_networks/district_heating_networks

potential investment of such systems.
The peak storage system includes a control algorithm that can precisely control the processes and its self-learning algorithm aims to save as much energy as possible. It will run on ConnectPoint's control system.
By the year 2030, €28.71 MEUR will be saved through the additional effect of the above-mentioned features.

3.4 Intelligent District Heating Platform and Demand Response program

For the IDHP platform and the DR program, a breakdown of the proposed CAPEX & OPEX is presented below:

- CAPEX - Implementation of the IDHP and DR program: €1.8 MEUR. This includes the analysis for integration, root cause analysis to improve the current energy savings offering, software roll-out, and algorithms tuning.
- CAPEX - IDHP hardware and installation: €4.9 MEUR, including the installation of the generic controller and temperature sensors in 5000 existing buildings.
- CAPEX - DR program hardware and installation: €18.8 MEUR. This includes a DR kit consisting of 4 thermostats and 4 temperature sensors each for 59.000 apartments.
- OPEX - License SaaS cost and support from supplier 5: €10 EUR per building, per month.

With the proposed investment plan, the total economic benefits (in Figure 9 below) associated with the IDHP and DR program will be €39.7 MEUR by 2030 - please refer to the feasibility section to see the details of the proposed business model. The quoted amount includes shared energy savings, decrease in heat transmission losses, the increase in heat production efficiency, and the savings due to avoided emissions, also as presented in the chart below.

From the total savings, €7.3 MEUR corresponds to CO_2 avoided emissions. These savings will be obtained by reducing the forecasted reductions of 245.000 tons of CO_2 within 10 years and assuming an average price of €34 EUR/ton CO_2 (provided by the City of Helsinki). The main economic benefit is the share with housing associations of the achieved heat consumption savings which corresponds to €32M EUR.

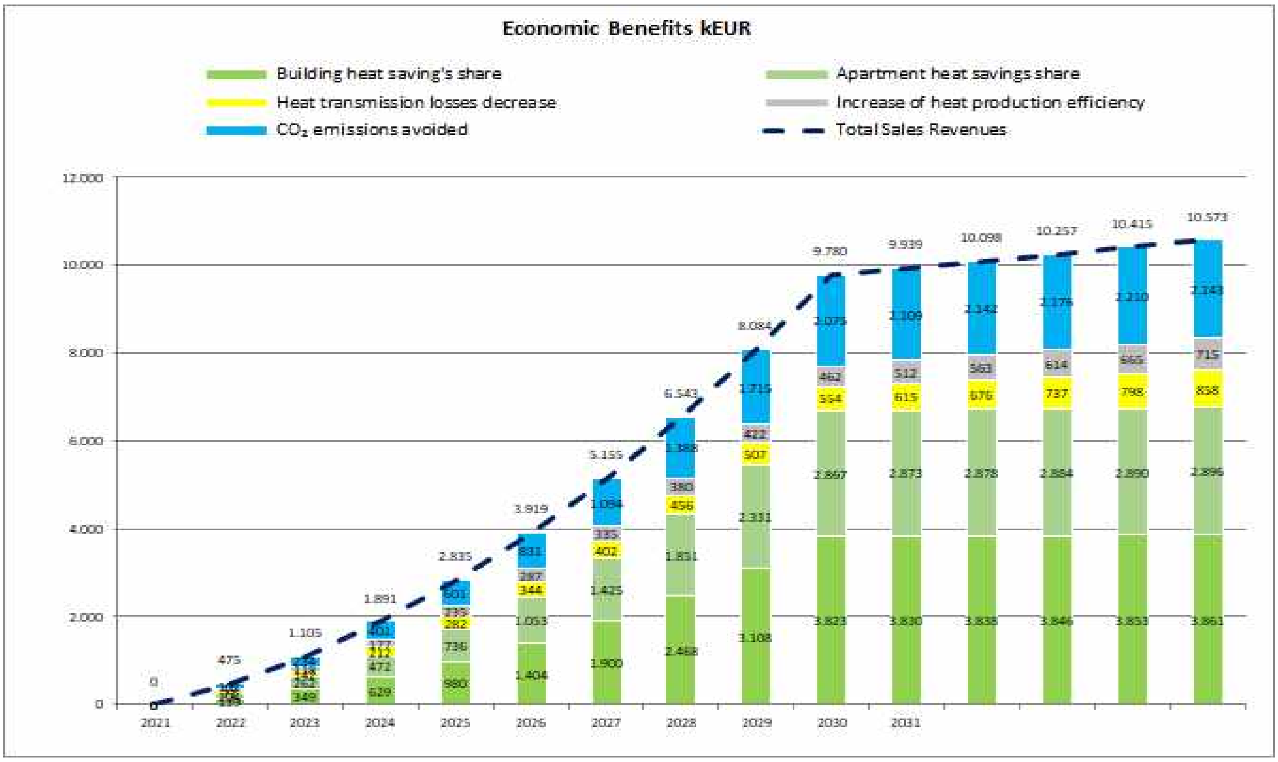


Figure 9- Annual savings from implementing IDHP platform and the DR program.

4. Implementation Schedule

The proposal aims at implementing the project in different stages, allowing de-risking at smaller scale and upscale it further on, as the risk decreases, and capital gets more affordable.
At the beginning, the project can be implemented on single modules as explained previously, representing a certain percentage of the overall DH need, and then based upon the project results it can be upscaled to the entirety of the city, in stages, to be evaluated by the Helsinki Municipality during the implementation stage. The proposed implementation timeline can be seen in Figure 10.

Figure 10- Visualization of implementation schedule of all solutions

The complete realisation of the project can take 4-9 years for the Solar thermal plants, based on the initial project results and the appetite of the Helsinki Municipality for the pace of implementation. A staged implementation for the whole solution is suggested in Figure 3, which can already start from the second half of 2021, depending on the time when the city of Helsinki can allocate the needed land area. Ideal unit sizes (solar thermal plants plus seasonal storage) were designed to be replicated to achieve optimized system operation and control, as well as scale benefits for the manufacturing and installation. In this proposal the plan is to start the implementation from the North-East plant (two areas planned as explained in chapter 2) and finalize it first, and to then make the installations at the North-West location. The implementation plan includes the suggestion to establish a collector assembly factory in the greater Helsinki area to produce major parts of the collectors close to the installation sites. If implemented fully as suggested in this proposal, the factory would be operational by mid-2023. The investment costs of the factory would be taken care of by the suppliers.
The collector fields need to go through a normal building permitting process including the environmental impact clarification. When the land area(s) for the first or multiple modules would be allocated by the city of Helsinki, the permitting process should start immediately. For the first module and needed transmission line construction that should start already in Q2/2021 if the proposed start of the implementation would be wanted. For other land areas the permitting process would be good to start step by step during 2021 and 2022. For the seasonal storage the permitting process is supposed to take longer, since it would be built underground. Based on this assumption, its permitting process for the proposed implementation schedule should start during 2022.
The implementation schedule for all suppliers until 2030 can be viewed in Table 8. The solar thermal (ST) installation by modules is presented annually and cumulatively, until the target production capacity of 1,073 GWh is reached in 2030. The seasonal storage cumulative capacity is also shown, following the implementation of the ST modules but starting two years later in 2024 since solar thermal capacity installed before 2024 is relatively low, and thus solar thermal production can be fed directly to DH network. The production of solar thermal heat in 2024 is around 200 GWh which could potentially be stored in part by the Mustikkamaa storage to be completed in 2021, with a capacity of 11.6 GWh.

Table 8-Schedule for proposed added capacity annually for all solutions and cumulative number of installations.

Project/Contract Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2054
Production/Capacities												
Solar Thermal												
Solar Thermal capacity cumulative (GWh)	0	40	120	200	320	440	560	720	880	1,073	1,073	1,073
New ST modules installed (pcs)	1	2	2	3	3	3	4	4	5	0	0	0
ST modules cumulative (pcs)	1	3	5	8	11	14	18	22	26.8	26.8	26.8	26.8
Storages												
Seasonal Storage cumulative (MWh)	0	0	0	66,000	105,600	145,200	184,800	237,600	290,400	354,213	354,213	354,213
Number of peak storages cumulative (pcs)	50	150	250	750	1,250	2,250	2,250	2,250	2,250	2,250	2,250	
Peak storages cumulative (MWh)	3,600	10,800	18,000	54,000	90,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000
Digital Solution												
Number of building connected to IDHP (cumulative)		184	276	368	460	553	645	737	829	921	921	921
Number of apartments joining DR program (cumulative)		2210	3315	4420	5526	6631	7736	8841	9946	11051	11051	11051

For the peak storage installation, a specific assessment for the substations will be required, following which design would be automated and replicable within a very short timeframe. The manufacturing of a peak storage unit takes 4 weeks in the case of standard product utilisation and 6 weeks in case of unique products, whereas the manufacturing capacity is 50 units/month at the moment. Installation work is simple and can be executed by local subcontractors or employees of Helen, as it requires basic plumbing work and takes merely 1-2 days, so it is possible to start implementation and roll-out as early as 2021. In the year 2021, 50 peak storage facilities would be installed within different building types (residential dwellings, offices, factories, government buildings, hospitals) with the system sizes ranging between 1-5 storage units per system. In the following years, larger systems will be installed to bigger end-users (up to 10 pieces of storage facilities per installation) where the peak heating/domestic hot water need is the most crucial.

The IDHP and the DR program will be implemented in parallel with installation of the solar thermal units and storages. As presented in the table below, the implementation target is to connect 50% of the existing buildings to the IDHP and enrol 50% of the households living in those buildings in the DR program by 2030. To reach the mentioned targets, we assume that there is an adoption rate that will increase over the years as presented in the previous table.
The following table contains the assumptions considered for calculating the number of buildings in Helsinki connected to IDHP platform and DR program.

Table 9- Assumptions for number of installations with IDHP platform and DR program

Item	Value	Description
Number of substations in the city	Substations = Total number of buildings	As per the bootcamp
Building stock 2017	9619	Taken from Helsinki's statistics portal
CAGR (2013-2017)	0.84%	Taken from challenge report (2013-2017)
Building stock 2021	9946	Forecasted
Buildings connected to the IDHP	4973	Total by 2030 (including)
Apartments participating in DR program	59676	Total by 2030 (including)
Coverage of DR program	50%	Percentage of users from the new buildings connected joining the DR program

Since Helen is defining the energy performance and certifications of the new buildings in the city, we assume that all the substations of the new constructions after 2021 will be equipped with the required hardware and technology to be connected to the IDHP platform.

As part of the Energy Renaissance Program, Helen plans to renovate 350 privately owned buildings per year as of 2021. Therefore, we assume that during the renovation the buildings will be equipped with the generic regulator so that they will be connected to the IDHP. The connections of those 350 buildings per year were not included within the CAPEX plan. The 350 buildings per year, represents 3.5% of the existing building stock; in combination with the capital plan proposed (IDH & DR program), 85% of all existing buildings would therefore be connected to the IDHP within a 10-year period.

The implementation of the IDHP and DR program will be carried out in 3 stages:

1. **Analysis and integration stage:** In the first year, which involves integration of existing heating network's IT with new IOT components. This also involves setting up the IDHP platform by connecting legacy OT/IT systems and the execution of a root cause analysis of the current energy savings service.
2. **Production rollout:** From the second year on, the production will commence and all software components of IDHP will be set up. Connection of the building's substation and the distribution and enrollment of the households to the DR program will be launched. As mentioned, we assume that the adoption rate of the services will increase year-on-year as presented in the previous table.
3. **Adoption increase:** In the third and fourth year, besides adding buildings to the IDHP and enrolling citizens to the DR program, the models and algorithms will be tuned. This stage assumes constant monitoring of the system, retraining algorithms based on the new sources of data, and improving the optimization factors of the system. The algorithms become more aware of citizens' preferences, building specifics, response to gamification, and economic viability of demand-side management for heat.
   The following years connection of new buildings and onboarding of new residents will continue following the proposed targets.

5. Implementation Feasibility

The entire project implementation plan was assessed along the six predefined factors: technologically, financially, legally, administratively, culturally, and ethically. The consortium also evaluated potential risks and risk mitigation measures, represented later in this chapter.

5.1 Technological feasibility

All the components of the proposed solution have proven the technical feasibility in various pilot and commercial projects. Solar thermal plants and seasonal storage are state-of-the-art technological solutions whose implementation is well known in the industry. It is simple to use and control and system components are reliable for over 25 years. Pumps need maintenance and possibly replacement during the lifetime and are of the same standard technology as used otherwise in DH networks.

The overall view of the full solution can be seen in the following Figure 11, where the five suppliers' technologies are represented with colours:

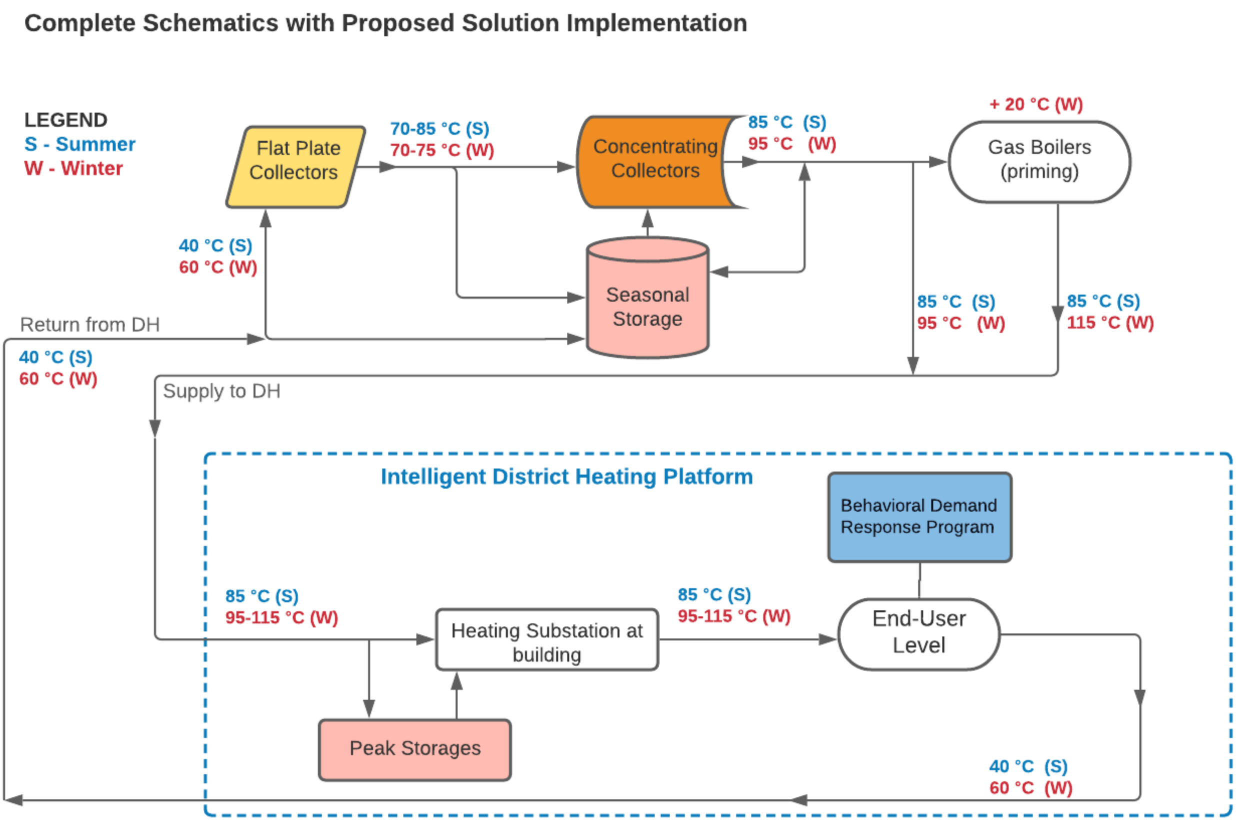


Figure 11- Complete Scheme of proposed solution including connections to DH network and temperature levels of supply/return for Summer and Winter operations

The integration to the Helsinki City DH network is technically rather straightforward, just like any other heating plant built in it. Nevertheless, there can be two challenges in this: Firstly, how to integrate the control into the whole systems control of the DH network. To achieve this, Helen's expertise would be required. Since there are already several different energy sources included in the system, and Helen is managing the system efficiently, this challenge would be easily overcome with a joint effort during implementation. Secondly, how to connect the new plants into the network in regard to heat flow. A separate location analysis with Helsinki would be required to assess this, whilst the modular structure of our solution would help to mitigate any potential issues encountered.

The installation of short-term peak storage facilities is also rather straightforward through typical plumbing works with the support of installation manuals. The connection of an individual or a pack of peak storages should be made between the supply and return pipeline with three-way valves and/or T-junctions.

There are two options to install peak storages:

- Option 1: to the secondary side of the end-user, inside the building in the substation.
- Option 2: to the primary side, controlled and owned by the DH company, though located inside the substation - this option might be more beneficial for Helen to realize savings.

The IDHP generic heating substation controller is built as an add-on to existing network controllers and systems, easy plug and play installation, not requiring retrofitting. The main engagement needed for this is with Helen's IT department to adjust IDHP algorithms to the planned and existing infrastructure. The various software functionalities of the IDHP platform will be created and/or adapted to specific Helen needs based on ConnectPoint experience with large heating networks and details agreed upon in the analysis stage of the project. The greatest challenge in the implementation will be the creation of a compelling demand-side response scheme and user-engagement into it.

5.2 Financial feasibility

The proposed solution is a no-regret solution. It can be implemented, integrated, and financed stepwise (fully adhering to the European taxonomy framework), since the solution is modular and highly scalable. It is proposed to start the implementation in a first step with a downsized system (single module of 40,000 MWh) representing ca. 3.85% of the total size. Advantages are already a feasible business case at this size, economy of scale and a de-risking (technical, business, governance) approach to enable potentially needed external investments/capital at improved rates. Moreover, it enables an earlier positive cash-flow, in combination with a long-term off-take agreement with the city of Helsinki, this provides the right ingredients to scale-up and define the final financial model for the full implementation.
The LCOH is calculated without any subsidies. The typical Energy Aid (from The Ministry of Economic Affairs and Employment of Finland) for solar thermal projects is 20% of the investment. Because of the scale and innovation involved in the project, it would most likely receive even higher subsidy, which would have a significant positive impact on the LCOH. One suitable subsidy scheme could be the Innovation Fund[5], which is providing EUR 10 billion of support over 2020-2030 for the commercial demonstration of innovative low-carbon technologies, aiming to bring to the market industrial solutions to decarbonize Europe and support its transition to climate neutrality.
The project managing entity of this consortium has been instrumental in securing large ticket investments from institutions such as the European Investment Bank to build manufacturing plants or invest in renewable energy projects, for several assets within its investment portfolio. Other innovative and favourable finance options such as green bonds might also be feasible depending on the requirements of Helsinki and will be investigated.

As the implementation of the IDHP platform involves multiple actors outside of Helen's scope, it is essential to explain how the business model of this solution will work.

1. Since most of the city's substations belong to the housing associations/housing cooperative (Helen's clients), the connection of the existing buildings to the IDHP will be offered by the city of Helen as an energy savings guarantees contract. Under the ESCO agreement, Helen will become an energy savings system operator and will fund all costs associated with the connection of the buildings to the IDHP (i.e, installation of the regulator, sensors, etc.). Under the mentioned agreement, Helen and the housing communities will split in equal parts (50% each) the energy savings. Helen and other district heating companies in Finland and Europe (e.g., Poland, Germany, Austria) offer energy savings services for housing communities under the same business model; however, this particular service has a low adoption rate in Helsinki as per the information collected during the Bootcamp. For that reason, we have proposed a detailed business model in this section and additional engagement strategies in the DR program section. Furthermore, a root cause analysis of Helen's current energy savings offer should be performed (included in CAPEX) to identify the activities and communication strategies that will increase engagement levels between the housing communities and Helen.
2. The business model consists of a B2C agreement between Helen as energy saving services system operator, the housing communities (customers), and Helen as energy producer and distributor. In this case, the production, distribution, and provision of energy saving services can be carried out by a single entity, Helen. It is also possible to separate the activity of the service provider into a special purpose company (SPV) owned and managed by Helen. The energy savings service system operator

[5] https://ec.europa.eu/clima/policies/innovation-fund_en

will be responsible for the operation, maintenance, and billing of the substations connected to the IDHP. The main task of the energy saving service operator is to optimize the operation of the heat substations, reduction of heating parameters during specific periods (night, empty building, holidays) and to use thermal accumulation of buildings to optimize the operation of sources. This reduces customers' heat consumption and CO_2 emissions.

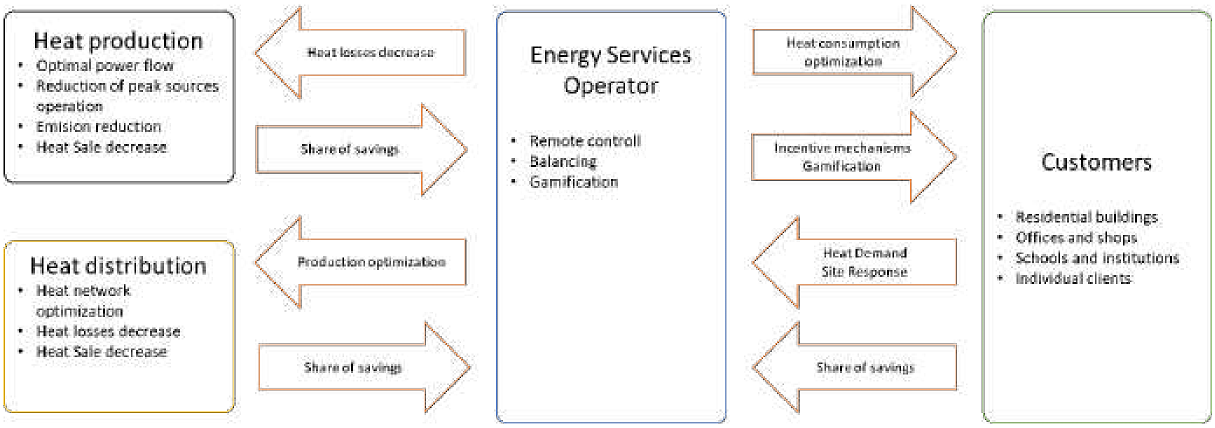


Figure 12- Representation of Business model for IDHP Platform with the multiple actors required.

Finally, Helen's loss of sales volume is compensated by housing communities thanks to the savings sharing agreement. It should be noted that the margin on heat sales can be several percent for the provider. If the heat consumption is reduced, 100% of the value of the avoided fee can be shared with housing communities (Helen's clients) to cover the costs of providing services and lost profits of the supplier.

5.3 Legal and Administrative feasibility

The proposed implementation does not raise any ethical, legal, cultural, or similar challenges as far as we can assess.
All the personally identifiable information (PII) gathered via the DR gamification mobile application, will be stored locally in each building inside the local database of the communication gateways/generic controllers. The local databases are secured and encrypted. Additionally, the city of Helen can select the data that will be synchronized to the IDHP platform to maximize the data privacy of the residents. The communication channels are secured, and the data transferred is encrypted. The legal, administrative, and ethical feasibility of the IDHP is also assured.
The personal data will be handled according to best practices, Helen standards and in Finnish GDPR-compliant way.
The whole IT architecture is designed to meet mission-critical standards and the final deployment will be consulted with IT security departments of Helen and adjusted if needed.

5.4 Risk Factors and Mitigation Measures

The following table 10 summarizes all perceived risks for the implementation of this solution as well as the mitigation measures planned to overcome those.
Table 10- Risk factors and mitigation measures summary

Risk factors	**Possible impact(s) on the implementation schedule**	**Likelihood** *1=very unlikely ..2..3..4.. 5=very likely*	**Mitigation measures**
Acquisition of the access to needed land areas will take longer than anticipated due to city's activities or will need to be divided on more locations than planned.	This could create delays in building the modules, so the complete system with all modules could be ready later than 2029 or the planned increase of clean solar heat could be slower than planned.	2	System planned to install on two locations. If access to land is delayed in one site, the other one can advance faster. Also build in some flexibility in the delivery capability, so possibility to speed up delivery to some extent, if delayed.

One of the five companies delivering their technology in this project would have problems in their delivery.	To some extent the planned increase of the heat production is dependent on all of them being able to deliver their part according to the plan. If one of them were to experience delays, others might also be delayed and that would endanger the overall schedule.	3	The five partners would establish a consortium to make the delivery and form/hire an experienced project team with a strong mandate to manage the whole project. Contractual terms and conditions with the customer investing in the system would be designed to support the capability of companies to keep their delivery schedules.
Low adoption of the energy services to connect the substations to the IDHP.	This could create delays as the projected rate of new buildings connected to the IDHP every year will not be reached.	3	Helen will offer the connection of the existing buildings under the energy savings guarantees contract. This business model has a high adoption in Europe and has been proven to work in other cities in Finland.
IT project related risks - access to information, lack of interfaces of current systems, lack of documentation	This could increase cost of the implementation, its complexity and stability as well as prolong the schedule of the project	2	Information provided by Helen during the workshops shows that the company IT architecture is modern and open for integration of new solutions which reduces the risk. In any case, an elaborate architecture/planning stage is planned at the beginning of the project to identify and mitigate detailed risks before they materialise.
User reluctance to engage into demand-side management	The more actively people participate in the demand side management, the better we can reduce the peaks and avoid CO_2 emissions due to peak sources.	3	The solution proposes deployment of gamification and popularization of it among the end-users and customers. Gamification would be based on two drivers: • economic driver (real-time cost information in each room, based on in-house temperature and possible savings thanks to it change) • well-being driver - information on how green the heat is and allocation of special green heat points
Language-, cultural differences and resistance to change hinder smooth implementation of the project	delay	3	Include local parties in all levels of the governance structure. Define project communication strategies
Insufficient local contractors available for installation work	delay	2	Arrange training and education of technical staff as part of the program. Align with educational institutes for young talent and retraining initiatives.
Price change higher than anticipated for important resources/materials	Higher costs than expected	2	Arrange long term contracts

5.5 Additional Benefits

In the summary the main advantages of the solution are listed. Below, possible additional benefits are explained.

Job Creation
The realization of the project as described in this proposal would create between 58-70 FTES (local jobs) throughout the whole project execution stage both by the manufacturing of collectors and during the installation of the systems.
In the manufacturing of the collectors at the planned local manufacturing factory the number of full-time jobs would be around 50, for years 2023-2030. Probably also after that since the same product would be exported to other installations or delivered in Finland. Before the local factory would be operational, there would be approximately 20 new jobs created by this project at the Suppliers' 1 and 2 existing facilities.
The installation of the systems, including ground preparation, piping, installing the collectors and pumping stations, would be mostly done by subcontracting the work to local companies. This would also create new jobs in the Helsinki area. The deliveries are project based, so would therefore not consist of continuous work at the sites throughout the year, however, calculating the jobs as annual full time employments (FTEs), approximately 12-15 FTEs would be created in the first two years, and for the higher installation and capacity increase pace, 30-35 FTEs. The same applies to constructing and installing the seasonal and peak storage facilities. To build the seasonal storages would require approximately 15-20 FTEs for years 2023-2030.

Oil refinery residual heat
According to preliminary geo mapping, some of the most suitable locations for solar heating installations are located on the axis between Östersundom and Söderkulla on the Eastern side of Helsinki. Using a solar heating transmission line also for transferring heat from Kilpilahti oil refinery could bring significant synergies for both projects. The transmission line could be used for providing steady base load from refinery residual heat, while solar heat usage could be allocated more on peak load hours.

Innovation - Development of a smart heating network in Helsinki

In opposition to electricity, for heating, smart meters to measure individual heat consumption are not widely spread. Thus, it is not easy to engage with the customers in the efficient planning and use of heat, which is a critical factor for smart grids' success. For that reason, the heating costs allocation solution, in combination with the gamified-based DR program, will allow the city of Helsinki and Helen to create a smart district heating network. After the IDHP and DR program's deployment, Helen will be able to identify what is required for customers' heating-related behaviour change to achieve active participation and engagement in the district heating system.

6. Reliability and security of supply

The solution considers today's requirements of the system plus predicted demand reduction, Helen's indicative replacement technologies and the technologies currently in use such as gas boilers. The yearly production profile of solar thermal plants does not usually match the yearly demand profile, however with correctly sized seasonal storage facilities complementing it, the seasonal imbalance is solved. Without storage, the district heating system must continuously meet the actual needs. In addition, to reduce the peak demand and increase local consumption of solar thermal heat, small scale thermal energy is stored on a substation level.

The security of supply needs to be sufficient throughout the year to balance the supply-demand discrepancy created by Salmisaari B's phase out. To match the yearly demand of the whole DH network, a thorough analysis of the multiple heat sources, their merit orders and Helen's future plans was performed.
As a high-level view, the coal CHP plants or pellet HOBs operate as base load throughout the year, as their fuel prices with taxes included are approximately at the same level. Depending on electricity price, heat pumps are next in order. Heat pumps are used especially during the summertime, as described in the background report. Gas CHPs have not been used much recently due to low electricity prices but may be operated when gas and electricity prices are within feasible range. Other heat centres (HOBs) are utilised mostly during winter to maintain network temperature levels around the large network.
Considering all this given information, both peak storage and seasonal storage will contribute to optimize the mix of heat sources, increase the share of non-controllable renewable energy sources (solar energy, intermittently available industrial waste heat, heat pumps, etc.). From an economic point of view, the

composition of heat sources and storage units can be optimized on the basis of unit costs, thus avoiding the operation of expensive and CO_2 -intensive peak heat sources.

6.1 Heat balance

The monthly balance of all heat sources in 2030 will look as follows:

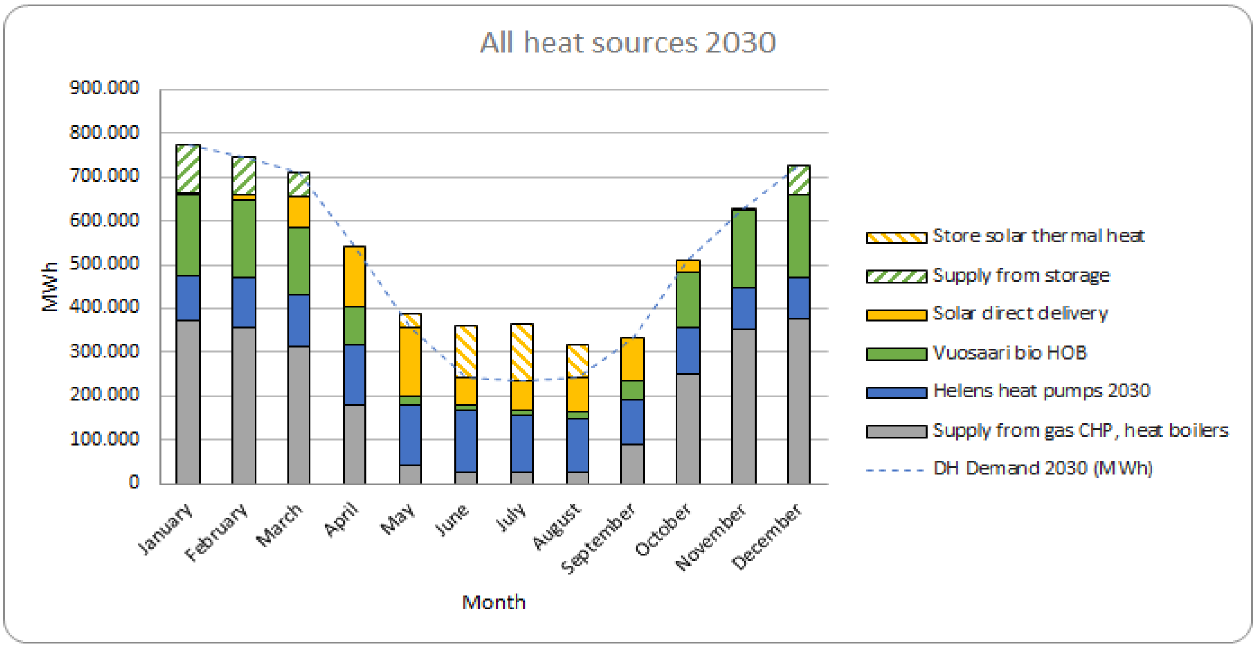


Figure 13- Monthly balance for year 2030 with all heat production sources.

The energy balance in figure 13 above shows how the demand of each month is supplied. The summer supply is clearly different from the winter supply. In summer, heat is primarily supplied by Helens heat pumps and the solar thermal heat. Also, in summer there is a large solar thermal heat surplus, which is stored in the seasonal storage. The rest of the summer demand is supplied by a selection of dispatchable sources, such as biomass, gas CHP and heat boilers. During winter, the production delivered by both Helen's heat pumps and the direct solar thermal heat, is lower. Other sources produce at higher capacity, such as the seasonal storage (with stored solar thermal heat), gas CHP, heat boilers, and biomass.

The assumptions on the energy balance are explained in more detail below. These assumptions may change over time and may need to be corrected. However, due to the scalability of the solar thermal plant, our proposal has the flexibility to be adapted to demand. Our assumptions are based on the information provided in this challenge.

First, the demand profile of 2030 is determined with the following assumptions:

- The domestic hot water demand is 2.275 GWh/year. This is an increase compared to 2018 due to an increase of inhabitants.
- The space heating demand is 3.125 GWh/year. This is a reduction compared to 2018 due to energy efficiency measures planned by the city.
- The total demand is 5,400 GWh/year, as provided in the challenge.
- The losses are assumed to be 644 GWh/year.
- The total heat production is 6,044 GWh/year.
- For the calculated demand per month, see graph in attachment (page 3).

Secondly, the production of renewable sources in 2030 is determined, based on the following assumptions derived from Helen's documents. The indicative replacement plans will be operational by 2025 and the following specific assumptions of utilization rate for each of the sources is presented in the table below.

Table 11-Assumptions summary for Heat production sources in Helens' Indicative plans

Renewable source	**Production**	**Full load hours**
Heat pump: Katri vala (2018)	580 GWh	5800 (mainly summer)

Heat pump: Katri vala expansion (2021)	130 GWh	8760 (baseload all year)
Heat pump: Seawater (2022)	350 GWh	8760 (baseload all year)
Heat pump: Vuosaari (2022)	175 GWh	8760 (baseload all year)
Heat pump: Geothermal (20xx)	175 GWh	8760 (baseload all year)
Vuosaari Biomass HOB (2022)	1,170 GWh	4500 (mainly winter)

Thirdly, due to geographical constraints and maintenance, it is assumed that even in summertime, a small amount of dispatchable heat is needed, approximately 17%. This could be from biomass HOB, gas-CHP or heat boilers.

Fourthly, the amount of solar thermal heat production is determined by balancing all the above-mentioned sources with the monthly demand. In order to replace the coal and some of the gas-CHP and boilers, the total production of solar thermal is calculated at 1,073 GWh/year. Apart from the 17% dispatchable sources and the different heat pump sources, all heat demand in summertime is provided by the solar thermal plant. All surplus solar thermal heat is stored in the seasonal storage and used again when it is most valuable: approximately 6 months later during winter time (can be seen in figure 14). The seasonal storage total capacity is approximately 33% of solar thermal heat produced throughout the entire year.

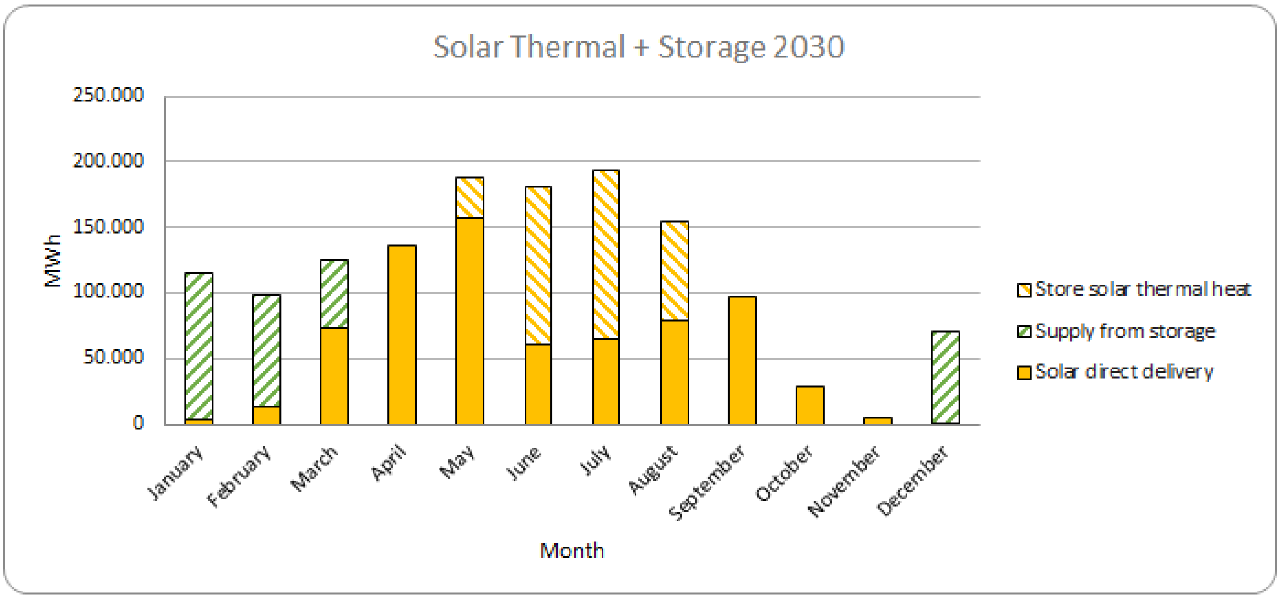


Figure 14- Monthly Balance for year 2030 of solar thermal heat + seasonal storage

Finally, the remaining heat demand (after, heat pumps, solar thermal and biomass) is provided by gas-CHP and heat boilers. The peak power capacity of the gas-CHP and heat boilers remains the same until 2030. These sources can easily provide the remaining peak winter demands since the winter demand in 2030 is lower than the current situation (due to energy efficiency measures) and because of the peak storage facilities.

The experience in the daily distribution of domestic hot water (DHW) demand is that the district heating system has to supply a substantial peak demand in the morning and in the evening.

By installing storage capacity into the district heating system, peak loads can be reduced, allowing the district heating system to provide only a basic performance: in case of peak demand, the storage and the district heating system serve the needs together, and when the peak demand does not occur, the storage can be charged and regenerated. On the other hand, the primary peak capacity can be increased, for example in the case of an already overloaded branch line or substation, the peak capacity can be increased with purposely designed and operated storages.

The peak storages can be used as a backup system in case the pipeline gets damaged or a heat source stops operating, the heat is continuously supplied with the help of the peak storage. By reducing the peak-load by 8.9%, the end-users of the overall district heating system will be more independent from the heat production. Mission critical buildings or substations can have an extra layer of security from a heat supply point of view.

In the event of a primary system failure, the heat storage will provide the necessary heating / DHW requirements. Security of supply is also very important in industrial processes and social institutions. Peak storage can avoid paying penalties for outages or customer churn due to dissatisfaction.

The IDHP solution allows remote heating substation monitoring and control of operation parameters. This monitoring will help to identify bottlenecks in the network or sections with over-capacity, detect failures, and predict the impact of parameter changes on energy consumption. These will improve the reliability of the network, by reducing and avoiding breakdown, optimizing the operational activities, improving the substation operation, predicting the future heat demand in buildings, and minimizing the heat and water losses.

7. Capacity

Long-term decarbonisation targets are expected to require investment in a wide portfolio of technologies, including renewables and large-scale storage which currently have relatively high costs. Evidence suggests that there is strong potential for cost reduction as the deployment of some promising technologies increases. It is important to mention, however, that until heat storage costs are reduced, the system cannot be fully transformed to a 100% renewable solution. To achieve such a target, there is furthermore a need for buildings refurbishment to increase their energy efficiency which requires further investment from the municipality.

Our solution is capable of completely replacing Salmisaari B CHP plant's production which we estimated to have a total annual production of about 1635 GWh (based on assumed working operation hours of the plant). The estimation of total solar heat capacity needed (1073 GWh, with 1039 GWh useful energy) was estimated through a complex balance of the whole DH system, considering the factors explained in the previous chapter. The following figure 15 represents the development of the different heat sources from present day until 2030.

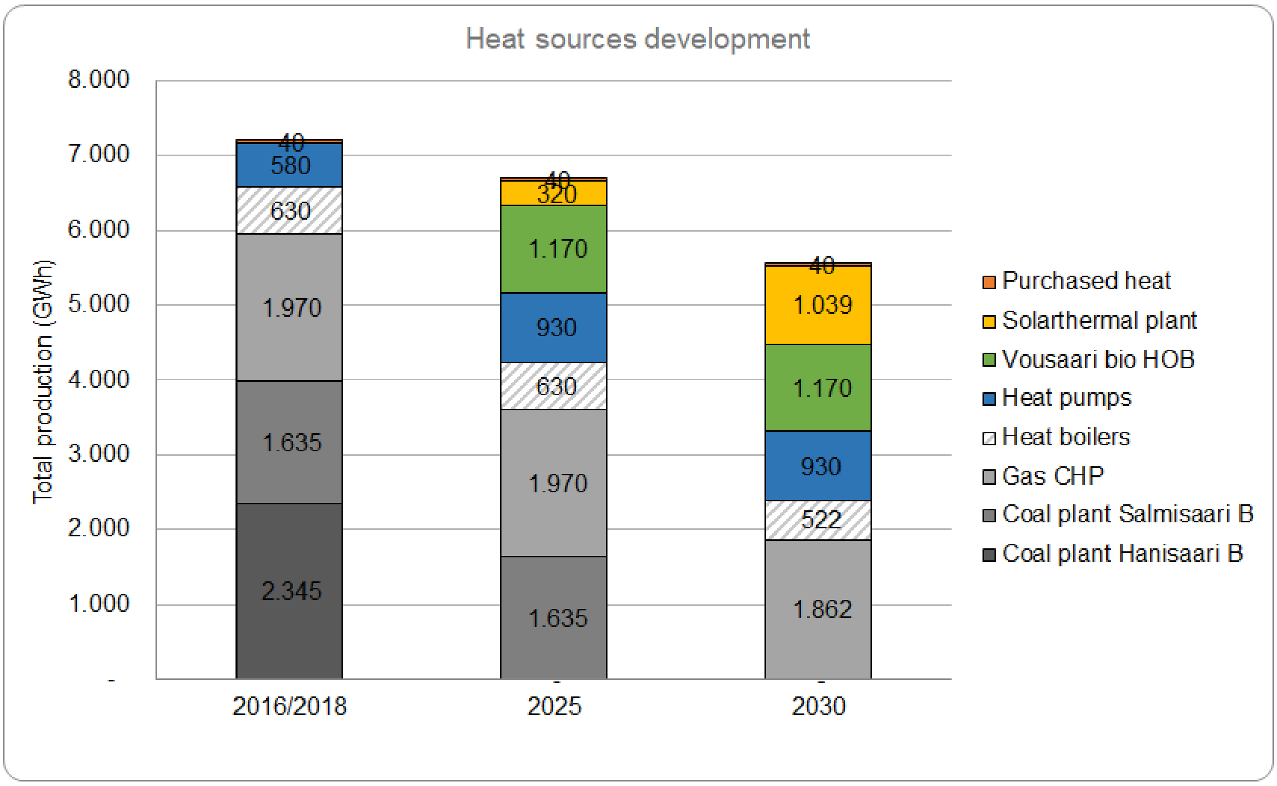


Figure 15-Graph of Heat Production development by the different heat sources

The figure 15 shows that both coal plants are eliminated until 2030. The solar thermal plants provide already 320 GWh in 2025, and 1,039 GWh in 2030, if the implementation schedule is followed as described in chapter 4. The heat pumps and purchased heat are assumed to remain with the same yearly production as today, accounting with the extra production of heat pumps in Katri vala station. The Vuosaari biomass HOB (260 MW) is assumed to be running 4500 hours yearly based on information by challenge organizers. Finally, depending on the utilization rate of the other dispatchable sources, the Gas CHP production can be slightly decreased to 1,862 GWh.

The cumulative peak storage capacities in 2030 are represented in the next table. With each peak storage tank holding a 75 KWh capacity, the peak storage facilities can provide 169 MWh of storage capacity.

Considering an operation mode of 2-3 cycles per day (charging and discharging), this would enable savings of 162.000 MWh yearly in the DH system.
By adding the size of the peak storages together, a 8.9% cumulative peak reduction can be achieved by 2030 on the full system and between 40-70% reduction can be reached for each of the substations, where the storage facilities are installed.

Table 12-Installed Capacity and yearly capacity of Peak Storage units in 2030

Number of storage cumulative (pcs)	2250
Peak storage capacity (MWh)	169
Peak power (MW)	450
Volume (m^3)	3825
Area (m^2)	2025
Yearly storage capacity (MWh)	162.000
Peak reduction (%)	8.9

The setup/operation of the system would be configured and aligned with the seasonal heat storage, daily demand data and production from solar thermal suppliers. By lowering the share of CO_2-intensive peak heat sources and increasing the share of renewable and waste sources which cannot be controlled, the average levelized cost of heat will be reduced.