FLEXYNETS

D3.2 - Integration of substations into DHC networks

Fifth generation, low temperature, high exergy district heating and cooling networks

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1 Summary

The work described in this report is aimed to link activities of Task T2.1, focused on single substations, to those of Task T3.1, focused on simulations of the network. As such, this report provides general considerations about both the network itself, the balancing of different substations within the network, and the type of connections expected between the substations and the network.

In T2.1, a set of substations (including supply stations) was selected. Within T2.4, detailed simulation activities were carried out to assess the performance of these substations under different configurations. Such analysis, while repeated for different temperatures at the network boundary, was focused on substations only, without discussing network-related aspects.

In T3.3, a network model has been developed in order to focus on distribution and balancing issues. The resulting model takes substation profiles as inputs and assesses the overall performance of the system, in order to compare different solutions. In contrast to Work Package WP2, this activity of WP3 does not enter in the substation details, but provides the complementary ingredients to analyse the system as a whole.

In order to properly connect these simulation activities, an overview of the overall system (network *and* substations) features is useful. This is the aim of this work, including an analysis based on simplified estimates rather than detailed simulations. The goal is to provide a qualitative description of the main effects at work and to identify the orders of magnitude of relevant parameters. Moreover, for each of the considered aspects, a description of how similar issues are solved in traditional networks is presented.

The main content is the following:

- A chapter is devoted to network balancing. This includes a selection of performance indicators for the system, a review of traditional networks, and a description of FLEXYNETS networks with a simple example.
- A chapter is devoted to residential substations. This section provides a summary of aspects related to how substations can be connected to the network, including for example specific issues related to differences between the 2-pipe and the 1-pipe options. Load profiles are also discussed.
- A chapter about power supply substations. Here, a short description of peculiarities of different sources is provided, along with a discussion of supply profiles for non-balancing stations.
- A chapter presenting parametric analyses on most relevant factors, analysing the application of FLEXYNETS in several possible scenarios and comparing its performance against other solutions.

Some conclusions are summarized in the final chapter. Complementary material, useful to understand some of the assumptions used in these estimates, is contained in the appendices.

2 Introduction

The FLEXYNETS projects is carried out in a context of potential expansion of district heating and cooling (DHC) markets. Thanks to the impact of DHC on overall energy consumptions (DHC+ 2012), it is indeed considered of primary importance to investigate all possible directions of improvement of this technology. A key element is typically identified in the reduction of the network operating temperature, in order to decrease thermal losses, as proposed for the so-called 4th generation district heating (Lund et al. 2014). The FLEXYNETS project aims to push this concept even further, considering a low-temperature network (at around 20 °C) based on distributed/decentralized heat pumps (HPs) and with the potential to simultaneously provide heating and cooling. Such a strong reduction in temperature either dramatically decreases heat losses and/or allows to use much cheaper pipes. Even more important, it opens up the possibility of exploiting more waste heat sources within urban areas, at temperatures not accessible for traditional networks.

Summarizing, the FLEXYNETS project focuses on the following main topics.

- Strong reduction in network temperatures.
- Integration of large amounts of low-temperature waste heat.
- Introduction of distributed heat pumps at user substations.
- High coefficients of performance (COP) values for the above HPs, thanks to the considered operating temperatures.
- Reversible operation, with simultaneous availability of heating and cooling and the advantage of offering two services with a single network.

These changes could allow the use of piping solutions without insulation, with significant investment savings for new installations with respect to traditional networks. On the other hand, additional costs for heat pumps are expected compared to substations based only on heat exchangers. Moreover, a low supply-return temperature difference is expected for this network (due to the typical operating conditions of HPs), requiring larger flow rates and hence larger diameters. Understanding advantages and disadvantages of this approach requires an investigation of several aspects, both on the technical and economic side.

The FLEXYNETS concept exhibits common points with water loop solutions found in geothermal applications and commercial buildings. Examples including groups of buildings are already available, though not on the large scale proposed in FLEXYNETS. Note that the temperatures planned for FLEXYNETS give rise to better COPs than in geothermal applications. Similar types of analyses are being developed also in other research projects (EU FP7 e-hub project 2010) and institutions (Foster S. et al. 2016).

This report tackles general issues related to the possible realization of FLEXYNETS networks, with special focus on the integration of different substations into the network. Here the term substation has to be intended in a broad sense. Indeed, while in traditional district heating networks the term substation is only used for energy delivery points, in the FLEXYNETS case – where the prosumer concept is introduced – the energy flow direction is not necessarily unique even for residential customers. Therefore, the distinction between generation and delivery points is less relevant and the term “substation” can be used to refer to any major component connected to the network (see also deliverables D2.1 and D4.1).

A discussion about how different heat sources and sinks can be integrated into the network needs to consider the problem of network balancing (see Chapter 3). Estimates about expected energy flows are hence useful. This also leads to the topic of assessing the convenience of a FLEXYNETS network in general. To this purpose, proper performance indicators must be chosen. These can be used to compare FLEXYNETS with other reference solutions. The different ingredients for the calculation of these indicators hence need to be defined and estimated. As far as the network balancing is concerned, it is also useful to distinguish between high- and low-temperature sources.

After providing a general overview of the system composition, it is useful to focus on the network interfaces for the substations studied in WP2. This includes the analysis of connection solutions for residential substations (see Chapter 4) and of the possible operational constraints on power supply substations (see Chapter 5). Within these chapters, examples of load and supply profiles are also presented. Indeed, heating and cooling profiles play a crucial role, also involving considerations about geographical dependence.

3 Network balancing

This subsection is devoted to the overall discussion of the network composition. It also includes comments aimed to compare traditional and FLEXYNETS solutions. To start with, a short subsection about performance indicators is presented. Afterwards, separate subsections for the traditional and the FLEXYNETS cases are provided, including some preliminary comparisons.

3.1 Performance indicators

This subsection includes a preliminary list of performance indicators which can be used to compare the convenience of different DHC solutions. Estimating performances is indeed the crucial step to assess the feasibility of a certain solution.

In general, the convenience of a DHC system can be evaluated according to several points of view. Main aspects include:

- Technical aspects. These include quantities as energy efficiency (e.g., thermal losses) and sustainability (e.g., in terms of fossil fuel consumptions and CO_2 emissions).
- Economic aspects. These include investment, and operation and maintenance costs, as well as considerations about energy prices for the customer. In a policy maker perspective, here it can also be interesting to assign CO_2 emission costs.
- Reliability and security aspects. These are sometimes related to the so-called "four As" (availability, accessibility, affordability, and acceptability), though other approaches are possible (Cherp and Jewell, 2014). A review on this topic can be found in Couder (2015).

Besides these elements, for large systems such as energy grids also externalities (pollution, social impacts) have a significant importance. A detailed analysis of all these topics goes however beyond the scope of this document, where only technical (including CO_2 emissions, considered in particular in the parametric analysis, section 6.5) and economic aspects are taken into account.

Below, a list of performance indicators taken from two different literature sources is presented. The first source is mentioned also in D3.1, but is summarized here again for convenience. These indicators were introduced for district heating. It should be noted that, in the case of cooling, the type of some effects is reversed: thermal losses to the ground become beneficial, while thermal gains (including those from pumping) become negative. Moreover, for reversible systems, different signs could be applied for different parts of the season. In order to simplify the discussion, in the following only the definitions for heating will be reviewed.

Quality indicators according to Pacot and Reiter (2011).

Five energy parameters are proposed.

Primary energy factor (PEF). This factor quantifies the primary energy which is used by a district heating network

$$f_p = \frac{\sum_j E_j\, f_{p,j} + E_{aux}\, f_{p,el} - E_{CHP}\, f_{p,el}}{E_{del}},$$

where E_j is the amount of the j-th primary energy consumed by the network, E_{aux} is the sum of auxiliary and pumping electric consumption, E_{CHP} is the amount of electricity provided by the combined heat and power plant (CHP) if any is installed, $f_{p,j}$ is the primary energy factor related to the j-th energy source, $f_{p,el}$ is the primary energy factor for electricity, and E_{del} is the amount of energy delivered to the consumers.

Relative importance of losses (RiL). This is related to the amount of heat losses present in the network

$$RiL = \frac{E_{loss} + E_{aux}}{E_{del}},$$

where E_{loss} is the amount of energy lost in the district heating (e.g. thermal losses through pipes). Note that pumping energy contributes to heating (through dissipation). In this document, we will prefer the use of the complementary indicator given by network efficiency (explicitly defined below when first introduced).

Primary energy efficiency. To properly include electricity, this parameter compares all the net delivered energy (e.g. thermal to the district heating network and electric to the power grid) to the primary energy use and is defined as

$$\varepsilon = \frac{E_{del} + E_{CHP} - E_{aux}}{\sum_j E_j\, f_{p,j}}.$$

Though useful from a theoretical point of view, the use of this indicator for comparing different networks is not straightforward, as it mixes thermal, electric, and primary energy.

District heating global efficiency. This is similar to a seasonal efficiency, being the ratio between all provided energies and all the necessary energies:

$$\eta = \frac{E_{del} + E_{CHP}}{\sum_j E_j + E_{aux}}$$

Energy share. This parameter represents the relative importance of all the energy sources providing heat to the network. It can be stated through the yearly energy consumption of these sources.

Besides these five energy parameters, other three parameters are suggested, as follows.

Subscripted Heat Power by km (SHP). It is expressed as the sum of the maximum callable heat power divided by the network length, hence yielding a power linear density.

Equivalent to nominal power duration (Heq). This parameter has the unit of time, being the ratio between an energy and a power

$$H_{eq} = \frac{E_{del}}{P_{HS,tot}}$$

where $P_{HS,tot}$ is the heating stations maximum power. It can provide a nominal estimate of yearly operation hours.

CO_2 emissions. This can also be evaluated as "avoided" CO_2 emissions in comparison to a proper reference system.

Additional indicators according to Henning (2012).

Finally, additional performance indicators can be used on the economic side. Some of them can be found in the reference considered here (Henning, 2012). Only the most important one is reported below.

Levelized cost of energy (LCoE). This yields the unitary energy cost, taking the ratio between the overall delivered energy and all the costs (investment as well as operation and maintenance costs). Initial investment costs have to be properly annualized through a discount rate r, yielding an annuity

$$a = \frac{r}{1-(1+r)^{-N}}$$

where N is the expected lifetime in years. One can see that $a \sim 1/N$ for $r \to 0$. One can also consider periodic investments annualized year by year (as in the case of a solar field slowly expanded in time). Slightly different formulas for the LCoE can be used, depending on the details used to calculate investment, operation, and maintenance costs. The formula used to analyse specific examples in the project will be explicitly clarified case by case.

In practice, the following main indicators were selected when comparing different system scenarios:

- Overall yearly costs including annualized investment costs, also represented with a splitting for the main system elements.
- Overall CO_2 emissions.
- Levelized energy costs, again calculated with the annuity method and distinguishing the contributions for heating and cooling, so that heating and cooling prices can be provided.

3.2 Traditional networks

In this subsection, a brief review of traditional networks is presented.

State of the art DH networks distribute energy from a centralized generation plant to a number of remote customers. In such a configuration, the elements connected to the network are simply the generation plant (e.g., one or more boilers), possibly some storage tank, and a large number of substations delivering heat to single customers. The network is typically a 2-pipe network, with the supply pipe at high temperature (e.g., 90 °C in 3rd generation DH networks) and the return pipe at a lower temperature (e.g., 50 °C again for 3rd generation networks), with only minor variations along the year. Substations hence do not need to be very flexible and the interaction with the network is rather straightforward.

The network control typically decouples hydraulic control (flow rate regulation) from temperature control. The main pump group is regulated in order to maintain a constant pressure difference between supply and return, thereby guaranteeing rather stable operating conditions at the different substations. The heat generation equipment is instead regulated in order to provide a constant supply temperature.

Priority rules can be introduced to regulate the heat supply from different sources, e.g., CHP, waste heat, boilers. Cheapest sources come first, provided supply-demand matching is guaranteed. The main objective of a district network is indeed to always satisfy the demand.

The largest traditional district heating networks have evolved in time into rather complex systems. It is nowadays common to find meshed networks with multiple generators, CHP units, and storage systems. This requires appropriate operation planning procedures.

Power stations are typically given by natural gas boilers, gas-fired CHP, high temperature heat pumps, and high temperature waste heat (see Frederiksen and Werner, 2013, for a broad overview).

In traditional networks, substations refer to units where energy is transformed from a higher to a lower level (in analogy with the traditional electric grid) and are based on simple heat exchangers.

Most performing networks can include very high shares of cheap heat. It is not uncommon to find DH networks where 50 % of the heat supply is provided by incinerators and 50 % by gas boilers, or networks where 60-70 % of the heat supply comes from CHP units and only 30-40 % from conventional gas boilers. This poses high challenges for other possible competitors. On the other hand, such well-performing networks often benefit of special conditions which are difficult to replicate in all contexts. Consequently, they cannot be taken as the sole reference to compare with.

In the next part of this section, we review some sizing aspects of thermal networks.

A network is typically sized to deliver a certain nominal thermal power[1], P_{th}. Moreover, a nominal supply-return temperature difference ΔT is chosen. Thermal power is related to temperature difference and volumetric flow rate Q_v through the equation

$$P_{th} = Q_v \, \rho \, c_p \, \Delta T \, ,$$

where ρ = 1000 kg/m^3 and c_p = 4190 J/(kg·K) are the water density and specific heat, respectively (here assumed to be independent of temperature). Having fixed the nominal power and the temperature difference, the nominal flow rate is also fixed.

The above procedure can be repeated for different network sections or subnetworks. For each section, the major design parameter to fix is the pipe diameter D. For small hydraulic plants, a typical sizing rule is to assume a flow velocity v = 1 m/s. Since $Q_v = v\,A$, where $A = \pi(D/2)^2$ is the pipe cross section, one can then calculate the diameter as $D = 2\sqrt{Q_v/(\pi\, v)}$. In the case of district heating, higher velocities are typically selected, though the condition $v \leq 3$ m/s is usually respected. The optimal diameter can be derived by a cost minimization procedure (Frederiksen and Werner, 2013; see below), where the cost function is given by the sum of pipe costs and pumping costs. Typical numbers then yield v = 2 m/s (which is also compatible with other flow constraints).

Thermal losses in pipes. Thermal losses can be calculated according to standard formulas, though the interaction between closely lying supply and return pipes can introduce some complications. For simplicity, we review here the case of a single pipe with inner diameter D, pipe thickness t_{pipe} and insulation thickness t_{ins}. Moreover, we only consider conduction losses, without including convection or radiation effects. The conductivities of the inner pipe and of the insulation are denoted as k_{pipe} and k_{ins}, respectively. The thermal resistance of each annular region of length L is given by $R_{th} = \ln(D_{out}/D_{in})\,/(2\pi L k)$, with straightforward meaning of the subscripts. The total thermal resistance is given by the sum of the single resistances. Since however $k_{ins} \ll k_{pipe}$, for a first estimate it is enough to consider insulation only. Power losses are then given by

[1] For this initial description, we neglect thermal losses along the network and hence do not distinguish between input and output power.

$$P_{loss} = \frac{2\pi L k_{ins}}{\ln[(D + 2t_{pipe} + 2t_{ins})/(D + 2t_{pipe})]}(T_f - T_{ext}),$$

where T_f is the bulk fluid temperature and T_{ext} is the temperature on the insulation surface. For a pipe with D = 0.2 m, t_{pipe} = 5 mm, t_{ins} = 5 cm, k_{ins} = 0.025 W/(m·K) and $T_f - T_{ext}$ = 60 K (reasonable parameters), one gets P_{loss}/L = 25 W/m. In order to consider both supply and return pipes, this value has to be multiplied by 2. For a power density[2] of 1 MW/km , one then gets losses of the order of 5 %. Typical heat losses in modern DH networks are in the range of 8-15 % (Frederiksen and Werner, 2013). Assuming a certain travelling velocity and distance, one can also estimate the temperature drop in a pipeline, which is useful to assess the temperature at peripheral substations.

Pumping power and related costs. Pumping power is given by

$$P_{pump} = \Delta p \; Q_v/\eta_{pump},$$

where Δp is the pressure drop and η_{pump} is the pump efficiency. The pressure drop is mainly determined by distributed losses and can be calculated with standard formulas based on pipe friction factors

$$\Delta p = f_F \rho v^2 L/R = \frac{f_F \rho Q_v^2 L}{\pi^2 (D/2)^5},$$

where f_F is the Fanning friction factor (equal to 1/4 of the Darcy friction factor), L is the pipe length, and $R = D/2$ is the pipe radius. For smooth pipes, a simple approximate expression for the friction factor is given by the Blasius formula $f_F = 0.079/\mathrm{Re}^{0.25}$, where $\mathrm{Re} = \rho v D/\mu$ is the Reynolds number and μ is the dynamic viscosity. Though the friction factor can be calculated in more accurate ways (e.g., taking into account the surface roughness of the pipes), the previous formula is enough to show that the dependence of the friction factor on the diameter is relatively weak and can be neglected in first approximation.

Yearly pumping costs per unit pipe length are given by $c_{pump,y} = P_{pump}\,\tau\, c_{el}/L$, where τ is a duration factor and c_{el} is the electricity unit cost. Note that, instead of using the real electricity cost, one can also use an effective value $c'_{el} = c_{el} - \eta_{pump} c_{th}$ which takes into account the fact that pumping energy is dissipated into heat and then delivered to the network, c_{th} being the thermal energy price (see for example Hlebnikov, 2007, and references therein).

Pipe investment costs. According to Frederiksen and Werner (2013), the investment per unit pipe length is roughly proportional to the diameter. In Deliverable D3.1, it is shown that the cost-diameter relation can be described more accurately by including a quadratic term besides the linear term, but this correction is neglected here for simplicity. In order to compare these costs with pumping costs, an annualized value must be used. Hence, a formula of the type $c_{pipe,y} = a(c_0 + c_1\, D)$ can be applied, where a is the annuity defined above.

Diameter optimization. Putting together the two calculations, yearly costs per unit pipe length are given by

$$c_{y,u}(D) = c_{pipe,y} + c_{pump,y} = a(c_0 + c_1\, D) + \frac{f_F \rho Q_v^3 \tau c_{el}}{\eta_{pump} \pi^2 (D/2)^5}.$$

The optimal diameter is obtained from the condition $\mathrm{d}c_{y,u}/\mathrm{d}D = 0$, i.e.,

[2] The value of 1 MW/km is reasonable for peak power. Average power is lower, hence the difference between the estimate and typical real values.

$$D = \left(2^5 \cdot 5\, \frac{f_F \rho Q_v^3 \tau c_{el}}{\eta_{pump} \pi^2 a c_1}\right)^{1/6},$$

which implies a relation $D \propto \sqrt{Q_v}$ (still under the approximation of constant friction factor). Since $Q_v = v\pi(D/2)^2$, solving for v one gets the same value for the velocity independently of the diameter, i.e., $v = \left[(2/5)\eta_{pump} a c_1/(\pi f_F \rho \tau c_{el})\right]^{1/3}$. Reasonable values to be used in this formula can be η_{pump} = 60 %, a = 5 %, c_1 = 1600 €/m^2 (so that laying down a pipe with D = 0.5 m costs about 800 €/m; see D3.1), f_F = 0.003, τ = 1500 h, and c_{el} = 15 c€/kWh, yielding about v = 2 m/s as anticipated above. Note, however, that in order to really benefit of this optimization procedure, reliable estimates of the used parameters have to be available.

It is also interesting to estimate pumping power with respect to thermal power (peak values). Using the above formulas, one gets

$$\frac{P_{pump}}{P_{th}} = \frac{f}{\eta_{pump}} L \sqrt{\frac{\pi \rho v^5}{P_{th} C_p \Delta T}},$$

which typically results to be of the order of a few percent[3]. Assuming that v does not depend on thermal power (as obtained from the previous analysis), it can be seen that $P_{pump}/P_{th} \propto L/\sqrt{P_{th}}$. Then, expanding a network in a context of linear power density $P_{th} \propto L$, one finds that relative pumping power increases with the square root of the network length, $P_{pump}/P_{th} \propto \sqrt{L}$.

3.3 FLEXYNETS networks

A first important distinction between the various solutions considered in FLEXYNETS regards the type of distribution network. Two options are considered:

- 2-pipe option. From a hydraulic point of view, this is identical to the traditional case, with one supply and one return pipe reaching each substation, at which two local supply/return branches divert. The flow is only driven by a centralized pump, which ensures the desired pressure difference between the inlet and the outlet of the substation. However, the presence of heat pumps introduces important operational differences with respect to the traditional case. For example, the supply-return temperature difference is expected to be significantly lower, e.g., 5-10 K instead of 30-40 K. This imposes different conditions on flow rate, for a given heat demand. Moreover, when reversible operation is taken into account, special considerations about warm/cold pipes have to be made.
- 1-pipe option. In this option, a single large pipe connects the different substations. At each substation, two smaller pipes (flow and return) divert from the main one to connect to the inlet and the outlet of the substation. The flow within these pipes is activated by a local pump according to the demand, while the flow in the main pipe is driven by a centralized pump. A proper balance between the two pumps must be ensured in order to avoid hydraulic short circuits on the main pipe. A small inlet/outlet temperature difference is expected at the substation pipes (e.g., 5 K, as for typical HPs), so that a minor effect on the temperature of the main flow is expected. However, after a large number of consecutive HPs all absorbing heat from the network, an observable lowering of the main pipe temperature

[3] Linear power densities of the order of 1 MW/km are common in the literature, corresponding to linear heat densities of the order of 1.5 MWh/(m·a) for operation times of 1500 h/a. For f = 0.003, η_{pump} = 60 %, v = 2 m/s, ΔT = 40 K, L = 30 km, and P_{th} = 30 MW one gets P_{pump}/P_{th} = 2.1 %.

will take place. This poses constraints on the positioning of sources and sinks along the network.

To start with, some of the parameters mentioned for traditional networks are reviewed.

Thermal losses. The same equations presented for traditional networks remain valid. The temperature difference between the fluid and the external environment is expected to decrease significantly, by a minimum factor of 4 and possibly down to 0. Then, removing the insulation can be feasible. For example, using standard high density polyethylene pipes (HDPE), thermal conductivity is of the order of 0.4 W/(m·K). This is about 15 times higher than the conductivity of typical insulating materials. The different pipe thickness and diameter also have to be taken into account. For example:

- Traditional network, D = 0.2, insulation 5 cm at k_{ins} = 0.025 W/(m·K), supply/return 90/50 °C, average pipe temperature 70 °C, external temperature 10 °C, 2-pipe: P_{loss} = 50 W/m.
- FLEXYNETS 2-pipe, D = 0.4 (see below for diameter considerations), pipe thickness 4.5 cm at k_{HDPE} = 0.38 W/(m·K), supply/return 20/15°C, average pipe temperature 17.5 °C, external temperature 10 °C: P_{loss} = 180 W/m.
- FLEXYNETS 1-pipe, D = 0.4 (see below for diameter considerations), pipe thickness 4.5 cm at k_{HDPE} = 0.38 W/(m·K), average pipe temperature 17.5 °C, external temperature 10 °C: P_{loss} = 90 W/m.

The thickness here assumed for HDPE pipes is in line with typical PN 16 (i.e., rated up to 16 bar) values (e.g., inner diameter 409 mm, outer diameter 500 mm).

In practice, one can assume to have thermal losses of the order of those of traditional networks, but without any insulation, provided the internal-external temperature difference is reduced by a factor of 15 or 30 for the 1-pipe and the 2-pipe case respectively. The alternative is of course to keep using insulated pipes, but dramatically reducing thermal losses even for the lowest insulation class (see D3.1).

Pipe diameter and pumping consumptions. The main equations presented for traditional networks can still be used. For a given thermal power, if ΔT is decreased by a factor 4, then Q_v is increased by the same factor. Assuming v is the same, then D must be increased by a factor 2. Consequently, Δp is roughly decreased by a factor 2. Finally, pumping power is increased by a factor of 2, being proportional to the product of pressure drop and flow rate. Summarizing:

- Larger pipes are needed with respect to traditional networks, roughly with a factor 2 of difference in the diameter.
- Higher pumping consumptions are expected with respect to traditional networks, roughly with a factor of 2 of difference.

This has consequences also on costs. However, the possible use of cheaper non-insulated pipes requires the use of different pipe cost parameters with respect to what mentioned in the subsection about traditional networks. These costs have been analysed in D3.1.

Note also that in the 1-pipe configuration, though a larger pipe is used, only half of the length is used.

Considered parameters. Before discussing the energy balance for these networks, some parameters are defined below for convenience.

- Network input thermal energy, $E_{netw,in}$.
- Network thermal efficiency[4], η_{netw}.
- Network output thermal energy, $E_{netw,out} = \eta_{netw}\, E_{netw,in}$.
- Net energy demand given by user needs, E_{dem} (e.g., actual demand for space heating).
- Energy supply from high temperature sources, E_{HTS}.
- Energy supply from high temperature sources with dedicated fossil fuel consumption, $E_{HTS,ff}$. This includes for example natural gas boilers.
- Energy supply from high temperature sources without dedicated fossil fuel consumption, $E_{HTS,\overline{ff}}$. This includes for example high temperature waste heat[5].
- Energy supply from low temperature sources, E_{LTS} (assumed free from dedicated fossil fuel consumption).
- Thermal efficiency of supply stations based on boilers (e.g., natural gas), η_{boil}.
- Electric grid conversion factor, η_{grid}.
- Residential heat pump coefficient of performance, COP (COP_{small} in case of ambiguity).
- Large heat pump COP, COP_{large}.
- Average operating temperature of the network, T_{netw}.
- Average temperature of the low-temperature sources, T_{LTS}.

<u>Comparisons</u>. Below, some comparisons are carried out. This aims to understand which are the minimum requirements needed to make FLEXYNETS competitive against certain reference systems.

<u>Sustainability of FLEXYNETS compared to traditional networks</u>. We consider a traditional and a FLEXYNETS network, both satisfying the same thermal energy demand E_{dem}. A first important comparison concerns sustainability in terms of fossil fuel consumptions (primary energy).

- Traditional case. Here, $E_{netw,in} = E_{dem}/\eta_{netw}$. Assume then that a fraction $f_{boil,trad}$ of the network input energy is satisfied through boilers with efficiency η_{boil}, while the rest is satisfied through recovered heat (incinerators, CHP, etc.). With reference to the previously defined parameters, $f_{boil,trad} = E_{HTS,ff}/E_{netw,in}$. The fossil fuel consumptions of this solution are hence $E_{ff,trad} = E_{dem} f_{boil,trad}/(\eta_{boil}\eta_{netw})$.
- FLEXYNETS case. Here, $E_{netw,in} = E_{dem}(1 - 1/\mathrm{COP})/\eta_{netw}$, as distribution takes place at a low temperature, so that HPs with performance COP must be used at user substations. Assume now that the fraction of the input energy provided by boilers is $f_{boil,FN}$. The fossil

[4] The network efficiency η_{netw} is the overall thermal efficiency including thermal losses and contributions from dissipated pumping energy.
[5] This includes also solar sources (at proper temperature) and all forms of high temperature waste heat (e.g., CHP, incinerators, industrial waste heat). In other words, the considered sources can involve consumption of fossil fuels (and possibly pollution generation), but with a primary purpose different from heating. Hence, this consumption would anyway be present, independently of its exploitation for a district network.

fuel consumptions of this solution are then $E_{ff,FN} = E_{dem}/(\mathrm{COP}\,\eta_{grid}) + E_{dem}(1 - 1/\mathrm{COP})f_{boil,FN}/(\eta_{boil}\eta_{netw})$.

It is reasonable to put the requisite that the FLEXYNETS solution be at least as sustainable as the traditional one. Consequently, $E_{ff,FN} \leq E_{ff,trad}$. The maximum acceptable value of the boiler fraction in the FLEXYNETS case, $f_{boil,FN}$, then occurs for the equality case $E_{ff,FN} = E_{ff,trad}$, which yields:

$$\frac{1}{\mathrm{COP}\,\eta_{grid}} + \frac{(1 - 1/\mathrm{COP})f_{boil,FN,max}}{\eta_{boil}\eta_{netw}} = \frac{f_{boil,trad}}{\eta_{boil}\eta_{netw}}$$

$$\Downarrow$$

$$f_{boil,FN,max} = \frac{\mathrm{COP}\,f_{boil,trad} - \eta_{boil}\eta_{netw}/\eta_{grid}}{\mathrm{COP} - 1} = f_{boil,trad} - \frac{\eta_{boil}\eta_{netw}/\eta_{grid} - f_{boil,trad}}{\mathrm{COP} - 1}\,.$$

The last expression puts in evidence that $f_{boil,FN,max} < f_{boil,trad}$, due to the fact that, at present, $\eta_{boil}\eta_{netw}/\eta_{grid} > 1$, while $f_{boil,trad} < 1$ by definition. This is the rather obvious result that – due to electricity consumptions of heat pumps – the FLEXYNETS solution increases overall fossil fuel consumptions unless a lower fraction of direct (i.e., related to the thermal input) fossil fuel consumptions is achieved. However, this lower fossil fuel consumption is what is indeed expected thanks to the easier access to low-temperature waste heat. The above relation also shows how much more waste heat must be integrated in order to obtain an environmental improvement. Using typical numbers, one has for example $f_{boil,trad}$ = 50 %, η_{boil} = 95 %, η_{netw} = 90 %, η_{grid} = 45 %, COP = 5, so that $f_{boil,FN,max}$ = 15 %. This shows that a significant increase of waste heat must be obtained to get an improvement with respect to an already efficient DH system.

On the other hand, when comparing to a situation where district heating is not yet present, one can expect that all thermal consumptions are satisfied by fossil fuel sources (e.g., by individual natural gas boilers). For $f_{boil,trad}$ = 100 % and with the same values for the other parameters, one then gets $f_{boil,FN,max}$ = 78 %. This means that the FLEXYNETS solution starts to be environmentally favourable already introducing a waste heat fraction of the order of 20 %.

In the above discussion, the possible fossil fuel savings obtained for cooling are not included. While the savings from improvements of the cooling supply may not expected to be a very large percentage of the overall energy balance of the system, they can further enhance the convenience of FLEXYNETS.

Another important factor which could significantly favour the FLEXYNETS approach in the future is the increase of the electric grid conversion factor. In the extreme case of fully renewable electricity, i.e., $\eta_{grid} = \infty$, one would get $f_{boil,FN,max} = f_{boil,trad}\ \mathrm{COP}/(\mathrm{COP} - 1) > f_{boil,trad}$ in the above equation. Of course, this does not mean that increasing the boiler fraction would be desirable, but that even increasing it a little – as shown by the ratio $\mathrm{COP}/(\mathrm{COP} - 1)$ – one would still consume the same amount of fossil fuels, thanks to the use of clean electricity. While this ideal scenario is clearly far from being realized, operating HPs during special times (partly allowed by the inertia of H&C systems) could allow to exploit excess renewable electricity (e.g., excess wind or PV production), practically exploiting clean electricity. This shows how important can be the interaction between different energy grids in the FLEXYNETS context.

Sustainability of different heat pump solutions. Besides comparing a traditional heat generation and distribution system with a FLEXYNETS system, it is also useful to compare the distributed HP approach proposed in FLEXYNETS with a centralized HP approach (partly adopted in some traditional networks). In practice, it is interesting to answer the question whether it is more convenient to directly distribute low-temperature waste heat at the original temperature and then to raise the latter at the user substations through local HPs or to raise the temperature through centralized HP and then to distribute the heat as in a traditional network (see Figure 1). Apart from cost considerations (a single large-scale HP can be cheaper than an equivalent set of small-scale HPs), one can make efficiency considerations, which depend on the type of heat source in the network.

As the focus is on heat pumps, for this analysis we simplify assuming η_{boil} = 1, thereby neglecting this factor. We also assume that the average temperature of the low-temperature sources, T_{LTS}, is the same temperature needed by users (e.g., 45 °C). Finally, when needed we specify the COP dependence on temperatures as $\mathrm{COP}(T_{evap}, T_{cond})$, where T_{evap} is the average evaporator temperature (energy source) and T_{cond} is the average condenser temperature (energy sink).

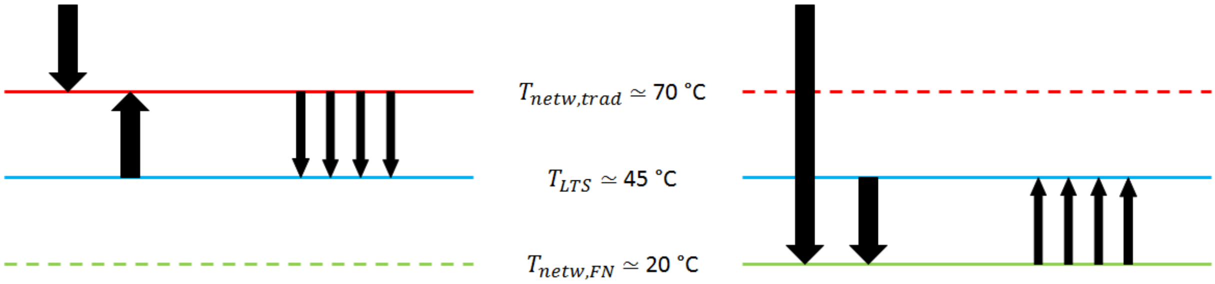

Figure 1. Centralized HP vs distributed HPs. Arrows depict energy flows from one temperature level to another.

Below, assuming to know the net energy demand E_{dem} and the available energies from fossil-free sources $E_{HTS,\overline{ff}}$, and E_{LTS}, for each of the two cases we calculate:

- The needed input energy into the network, $E_{netw,in}$
- The needed amount of high temperature fossil fuel sources (e.g., natural gas boilers), $E_{HTS,ff}$
- The primary energy (intended as fossil fuel derived energy) consumption E_{ff}

<u>Centralized HP</u>. For this option, it is assumed that the network is operated in a traditional way, with a high temperature (e.g., 90 °C) supply pipe and a medium temperature (e.g., 50 °C) return pipe. High-temperature sources directly deliver heat through heat exchangers, while low-temperature sources need (large, centralized) heat pumps. Users are directly supplied by the network through heat exchangers.

For the traditional case, one has $T_{netw} = T_{netw,trad}$ (average between supply and return). Moreover, $\mathrm{COP} = \mathrm{COP}_{large}(T_{LTS}, T_{netw,trad})$. The input energy required by the network in the traditional case is hence

$$E_{netw,in} = \frac{E_{dem}}{\eta_{netw}} = E_{HTS} + \frac{E_{LTS}}{1 - 1/\mathrm{COP}_{large}},$$

where $E_{HTS} = E_{HTS,ff} + E_{HTS,\overline{ff}}$ is the overall thermal energy supplied by high-temperature sources, as defined above. The energy from direct fossil fuel sources must then be

$$E_{HTS,ff} = \frac{E_{dem}}{\eta_{netw}} - E_{HTS,\overline{ff}} - \frac{E_{LTS}}{1 - 1/\mathrm{COP}_{large}}.$$

Note that, since one must have $E_{HTS,ff} \geq 0$, the last equation also yields a condition on the maximum amount of energy from low temperature sources which can be integrated in the network for given values of E_{dem} and $E_{HTS,\overline{ff}}$.

Finally, the primary energy consumption in the traditional case is hence

$$E_{ff} = E_{HTS,ff} + \frac{E_{LTS}}{\mathrm{COP}_{large} - 1} \frac{1}{\eta_{grid}} = \frac{E_{dem}}{\eta_{netw}} - E_{HTS,\overline{ff}} - \frac{E_{LTS}}{\mathrm{COP}_{large} - 1}\left(\mathrm{COP}_{large} - \frac{1}{\eta_{grid}}\right).$$

Distributed HPs. In this case, the network is operated at the average neutral temperature proposed in FLEXYNETS, $T_{netw} = T_{netw,FN}$. It is not crucial here to distinguish between the 2-pipe and the 1-pipe case, as the involved temperatures are anyway expected to be similar. Lower heat losses in pipes are expected with respect to the previous case (unless less insulated pipes are used). Possibly, a larger amount of low-temperature waste heat can be considered, as its integration is simpler and hence potentially more attractive in the absence of large heat pumps. At user substations, HPs with performance $\mathrm{COP}_{small}(T_{netw,FN}, T_{LTS})$ are installed. For the other parameters, the same nomenclature as in the previous case is used. One then has

$$E_{netw,in} = \frac{E_{dem}}{\eta_{netw}}\left(1 - \frac{1}{\mathrm{COP}_{small}}\right) = E_{HTS} + E_{LTS}\,,$$

where now, for a given net user demand, the thermal energy delivered by the network is reduced by the electricity contribution of small HPs, i.e., $E_{netw,out} = E_{dem}(1 - 1/\mathrm{COP}_{small})$. The energy from direct fossil fuel sources must then be

$$E_{HTS,ff} = \frac{E_{dem}}{\eta_{netw}}\left(1 - \frac{1}{\mathrm{COP}_{small}}\right) - E_{HTS,\overline{ff}} - E_{LTS}\,.$$

Consequently, the primary energy consumption becomes

$$E_{ff} = E_{HTS,ff} + \frac{E_{dem}}{\mathrm{COP}_{small}} \frac{1}{\eta_{grid}} = \frac{E_{dem}}{\eta_{netw}}\left[1 + \frac{1}{\mathrm{COP}_{small}}\left(\frac{\eta_{netw}}{\eta_{grid}} - 1\right)\right] - E_{HTS,\overline{ff}} - E_{LTS}\,.$$

Centralized vs distributed HPs. In order to clarify the comparison, it is useful to make some practical example. We consider a network with fixed final energy demand E_{dem} and fixed high- and low-temperature fossil-free sources $E_{HTS,\overline{ff}}$ and E_{LTS}, corresponding to 50 % and 20 % of the final demand, respectively. For clarity, we distinguish with the subscripts "trad" and "FN" the two cases, based on traditional and FLEXYNETS temperature levels. We assume the temperature values shown in Figure 1, i.e., $T_{netw,trad}$ = 70 °C, T_{LTS} = 45 °C, and $T_{netw,FN}$ = 20 °C. For the estimation of the COPs, we assume $\mathrm{COP} = \mathrm{COP}_C/2$, corresponding to an efficiency of 50 % with respect to the ideal Carnot value[6] $\mathrm{COP}_C = T_{cond}/\Delta T = T_{cond}/(T_{cond} - T_{evap})$. This yields COP_{large} = 6.9 and COP_{small} = 6.4 (as the ΔT is the same in the two cases, the difference is only related to the different average temperature). For simplicity, we assume the same network thermal efficiency in the two cases η_{netw} = 90 % and an electric grid conversion factor η_{grid} = 45 %. One can then calculate the needed amount of high-temperature thermal energy produced with fossil fuels in the two cases

$$E_{HTS,ff,trad} = E_{dem}\left(\frac{1}{90\ \%} - 50\ \% - \frac{20\ \%}{1 - 1/6.9}\right) = 0.38\ E_{dem}$$

[6] A slightly more elaborated formula is used in the scenario analysis of Chapter 6, as described in Appendix A. For this discussion, this simpler formula was preferred to avoid complications.

$$E_{HTS,ff,FN} = E_{dem}\left[\frac{1}{90\ \%}\left(1-\frac{1}{6.4}\right) - 50\ \% - 20\ \%\right] = 0.24\ E_{dem}$$

One can see that with traditional temperatures, the direct fossil fuel consumptions (e.g., from natural gas boilers) is higher. However, for the primary energy consumption one finds

$$\begin{aligned} E_{ff,trad} &= E_{HTS,ff,trad} + \frac{E_{LTS}}{\mathrm{COP}_{large}-1}\frac{1}{\eta_{grid}} \\ &= E_{dem}\left(38\ \% + \frac{20\ \%}{6.9-1}\frac{1}{45\ \%}\right) = 0.45\ E_{dem} \\ E_{ff,FN} &= E_{HTS,ff,FN} + \frac{E_{dem}}{\mathrm{COP}_{small}}\frac{1}{\eta_{grid}} \\ &= E_{dem}\left[24\ \% + \frac{1}{6.4}\frac{1}{45\ \%}\right] = 0.58\ E_{dem}\ . \end{aligned}$$

One can then see that, in order to have lower primary energy consumptions with FLEXYNETS temperatures, one needs to consider very high shares of low temperature sources. For example, in the extreme case when E_{HTS} = 0 (as in the case of geothermal systems) and using the same values for other parameters as above, for traditional temperatures one would have E_{LTS} = 0.95 E_{dem} and $E_{ff,trad}$ = 0.18 E_{dem}, while for FLEXYNETS temperatures E_{LTS} = 0.94 E_{dem} and $E_{ff,FN}$ = 0.17 E_{dem}.

Of course, centralized HPs do not offer the benefit of having a reversible network. In the case of significant cooling needs, the distributed solution is hence expected to be anyway superior.

4 Residential substations

As far as residential substations are concerned, the interaction with the network is affected by the operating conditions in several ways. This section deals with these aspects. Before discussing the case of heat pumps, relevant for FLEXYNETS, a brief review of the traditional case based on heat exchangers in presented.

4.1 Traditional residential substations

In traditional networks, substations refer to units where energy is transformed from a higher to a lower level (in analogy with the traditional electric grid). Key elements are given by heat exchangers, combined with mixing and control equipment. Substations are typically placed at each building connected to the network, though some other solutions exist (e.g., area substations, to serve local distribution networks, or apartment substations, to allow for specific regulation and billing at each flat in a building; Frederiksen and Werner, 2013). Moreover, substations may be owned either by the DH company or by the customer. Substations are typically found in prefabricated compact solutions and often include communication modules.

Substations for district heating are required to provide a low enough return temperature, otherwise negative impacts on the supply-return temperature difference – and hence on the network performance – arise (the opposite requirement holds for cooling networks, i.e., the return temperature has to be high enough). Clearly, two kinds of improvement are typically sought:

- Lowering of supply temperature to reduce heat losses (the opposite for cooling).
- Increasing the supply-return temperature difference to improve the power station and reduce pumping costs.

Hydraulic separation of the building circuit from the network circuit is typically required. In some cases direct supply is used, with the advantage of reducing investment costs for equipment, but with the major disadvantage of introducing a series of issues (both in terms of performance and maintenance). Sometimes, hybrid solutions are also possible: direct connection for sanitary water and indirect connection for space heating or vice versa. However, indirect connection seems at present the most diffused solution, providing a safer and more comfortable operation. Some variants of this connection can be found in the book of Frederiksen and Werner (Frederiksen and Werner, 2013). Similar considerations are valid for traditional district cooling substations (hydraulic separation and supply-return temperature difference as large as possible), though other aspects have to be taken into account (e.g., anti-freezing recirculation systems, air distribution system, possibly including humidity control).

The main aspects relevant for traditional heating substations are the following:

- Network supply temperature. A minimum inlet temperature at each substation has to be ensured. A proper control system (based on bypass flow activation, see Deliverable D4.1) is typically present for peripheral substations. The supply temperature at load plants has hence to include some margin with respect to this minimum value, in order to manage pipe heat losses in the different flow conditions. Of course, variations of the supply temperature affect the substation operation. This effect can be exploited by control. For example, it is possible for the network manager to slightly increase the network temperature (thereby “loading the network”) to prepare the system in view of peak load conditions.

- Network return temperature. It is convenient to have the lowest possible return temperature, in order to improve the efficiency of load plants. This is particularly important whenever these plants include combined heat and power (CHP) systems, as the electrical efficiency of the latter directly depends on this temperature.
- Maximum and minimum pressure. Operational limits of the installed components cannot be exceeded. Similarly, a minimum differential pressure across the substation has to be preserved, in order to ensure the proper flow. These hydraulic issues can be easily decoupled from thermal aspects in traditional networks.
- Space heating (SH) and domestic hot water (DHW) preparation interfaces. The interface with the network can be different, depending on whether a direct or indirect connection is used. Direct connection (where, e.g., the district heating water directly enters the heating terminals) has the benefit of reducing heat losses and minimum supply temperatures. On the other hand, indirect connection (where a hydraulic separation from the network is introduced via a heat exchanger in the substation) is safer, as it protects one plant from any issue occurring on the other and it allows the use of cheaper components on the local side (where lower pressure and temperature can be used). Note that the supply network temperature is fixed by the "worst case" in the network, i.e., by the highest minimum required temperature among all substations. This is affected by both the substation position and the local plant type. For example, in a network where all but one the connected buildings have a low-temperature heating system (e.g., floor heating), still the supply temperature would be fixed by the single building requiring the highest temperature.

Protection, control, and monitoring equipment includes pressure reducers, flow limiters, regulating valves, temperature sensors, heat meters. Focusing on the case of indirect connection, the main interface between the network and the residential plant is given by one or more heat exchangers (e.g., one heat exchanger for space heating and one for domestic hot water preparation). An example of a traditional substation is reported in Figure 2 (see also Deliverable D4.1).

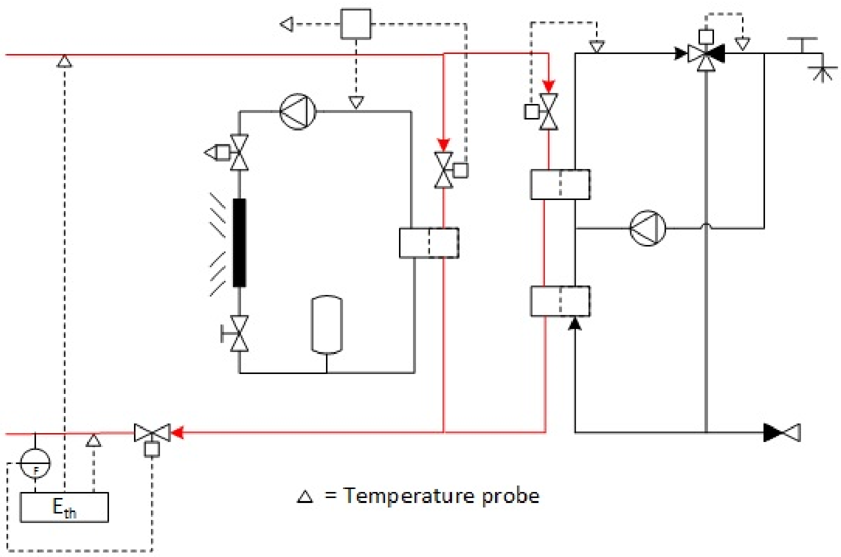

Figure 2. Example of a traditional DH substation (indirect connection for both space heating and hot water). A detailed description of this example can be found in Frederiksen and Werner, 2013. Probes denoted by a triangle are temperature sensors, while the probe denoted by an F is a flow meter. E_{th} denotes the heat meter.

4.2 FLEXYNETS residential substations

The actual structure of a FLEXYNETS substation is studied in WP2. Deliverable D2.1 already includes some proposals. The considered configurations are related to the systems studied in the Inspire project. In the latter European project, different renovation options were considered and a versatile plant was introduced, in order to allow for different connections. The different options considered in Inspire are represented in Figure 3.

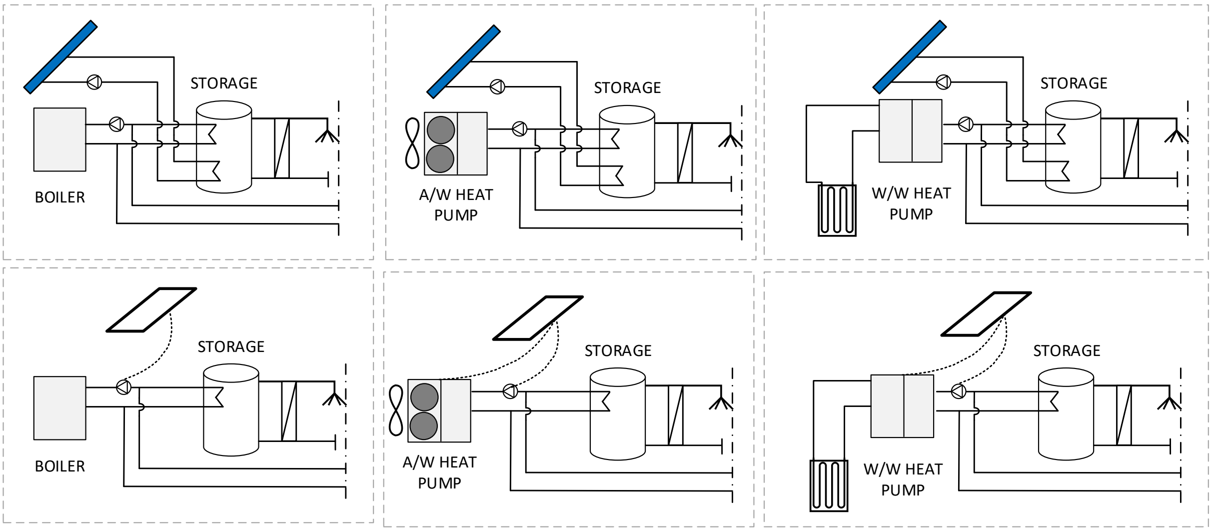

Figure 3. Generation renovation packages with solar thermal field (above) and PV panels (below) in the Inspire project. Three different generation units have been considered: boiler (either gas or biomass), air-water heat pumps, water-water heat pumps (as in geothermal application with ground source heat pumps). For each of these generation solutions, two options (with solar thermal or PV) have been analysed.

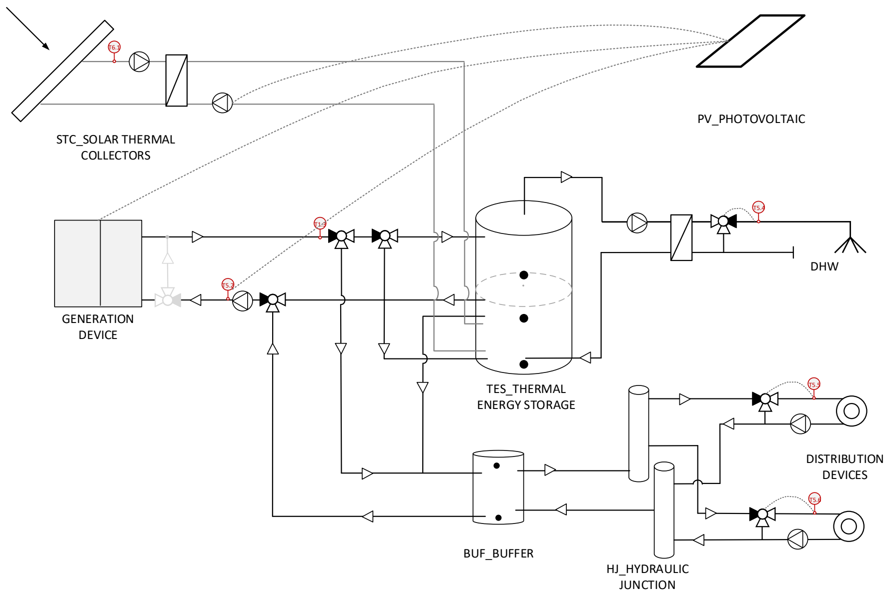

Figure 4. Reference H&C system used to simulate different Generation and Distribution Renovation Packages in the Inspire project. This flexible configuration was used to develop simulation models suitable to test all the considered subcases.

These different options share a common structure in terms of distribution system. Therefore, a unified modelling approach was possible, as shown in Figure 4.

In the case of the FLEXYNETS project, several similarities with the above configuration are present. In order to focus on the interaction between the substation and the thermal network, some components were however excluded from the analysis. The resulting system is depicted in Figure 5. This configuration was simulated in WP2 with different boundary conditions on the building side. In particular, specific building cases were considered (e.g., multifamily house with given number of flats, specific geographical location, etc.). The figure refers to the 2-pipe network solution, though the same analysis is valid also for the 1-pipe case. Indeed, the only relevant boundary condition on the network side is the network inlet temperature. The circuit with the 3-way valve and the pump on the network side can serve both the 1-pipe and the 2-pipe option, the pump being possibly "disabled" in the 2-pipe network case.

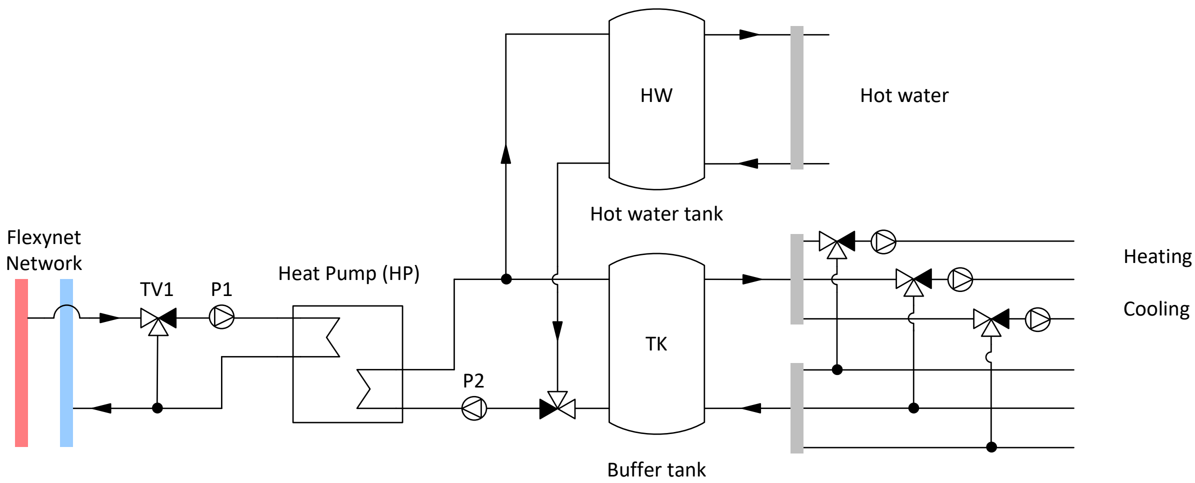

Figure 5. The FLEXYNETS residential substation used for simulations (2-pipe option; see also Deliverable D2.1).

Some interface-related issues specific of FLEXYNETS need to be discussed.

Network temperature and heat pump operational limits. Below, the operational limits of the HP model installed at the EURAC pilot laboratory are taken as an example. This is a heat pump based on the R-410A refrigerant gas, suitable for relatively low temperatures. While other HPs (e.g., those based on R-134a) can have different performances, similar order of magnitudes are expected. The operating temperature limits of the considered HP are summarized in Figure 6.

- Heating mode. In this mode, the heat pump absorbs heat form the network. Therefore, the network side corresponds to the evaporator side of the heat pump. Minimum and maximum network temperatures (in the absence of recirculation, see below) are then given by minimum and maximum evaporator inlet temperatures, namely $T_{evap,in,min}$ = 9 °C and $T_{evap,in,max}$ = 23 °C. The reported values hold assuming a temperature difference of 5 K between the inlet and the outlet of each circuit (i.e., the outlet evaporator temperatures corresponding to these two limiting cases would be 4 °C and 18 °C, respectively) and assuming a minimum outlet temperature on the user side of 35 °C (for a supply temperature of 30 °C for the user, the maximum acceptable network temperature would be about 19 °C). Minimum temperature is here limited by the use of water (water-glycol mixtures would allow temperatures even below 0 °C). The relevant boundary for FLEXYNETS applications in heating mode is hence $T_{evap,in,max}$. This is constrained by the operational limits of the refrigerant fluid used in the internal thermodynamic cycle. On the other hand, it is worth pointing out that the relatively high maximum condenser outlet temperature (up to 60 °C) could make these HPs suitable even for applications with traditional heating plants based on radiators.

- Cooling mode. In this mode, the heat pump rejects heat to the network. Therefore, the network side corresponds to the condenser side of the heat pump. Minimum and maximum network temperatures (again in the absence of recirculation) are hence given by minimum and maximum condenser inlet temperatures, namely $T_{cond,in,min}$ = 20 °C and $T_{cond,in,max}$ = 55 °C. As in heating mode, the reported values hold assuming a temperature difference of 5 K between the inlet and the outlet of each circuit (i.e., the outlet condenser temperatures corresponding to these two limiting cases would be 25 °C and 60 °C, respectively) and assuming a maximum outlet temperature on the user side of 10 °C (for a supply temperature of 15 °C for the user, the minimum acceptable network temperature would be about 27 °C). The relevant boundary for FLEXYNETS applications is hence $T_{cond,in,min}$. The constraint again depends on the refrigerant fluid limits.

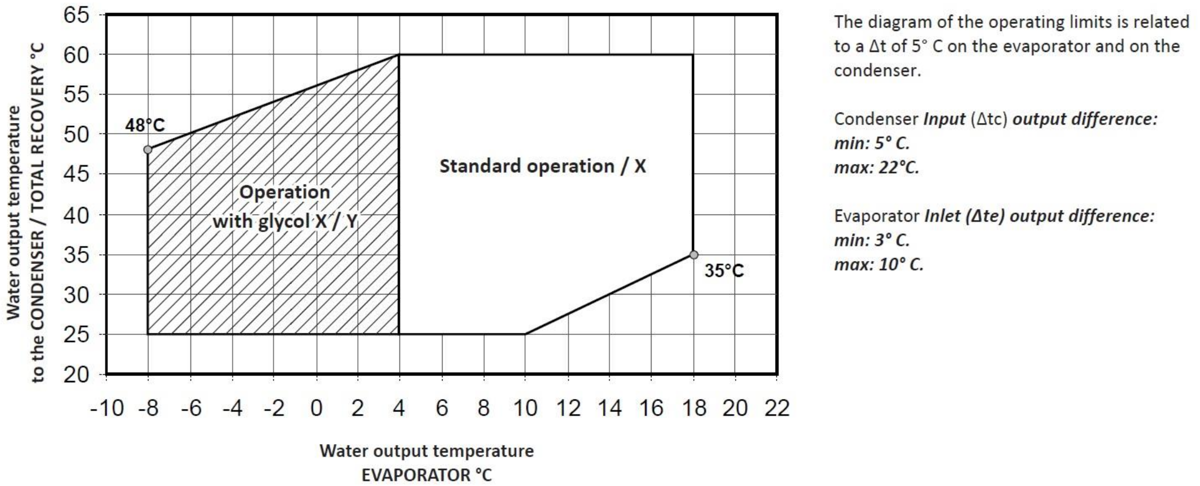

Figure 6. Operating range for the water-water heat pumps used at the EURAC pilot laboratory. They are typical commercial heat pumps used in residential applications. Two units with a nominal heating power of 25 and 32 kW are installed in the laboratory.

The above analysis is focused on the heat pump inlet temperature on the network side. Clearly, also the inlet-outlet temperature difference has an effect. Increasing the inlet-outlet temperature difference (e.g., reducing the flow rate), one could slightly enlarge the above limits. This is however a minor effect, introducing a margin of the order of 5 K.[7]

[7] For example, a ΔT = 10 K can be used. As the operational limit is based on the outlet temperature, this higher ΔT increases the admissible network temperature in heating mode to 28 °C and decreases the admissible network temperature in cooling mode to 20 °C. The best achievable performances are then COP = 6.46, with evaporator temperatures (network side) of 28-18 °C and condenser temperatures (user side) of 30-35 °C, and EER = COP-1 = 5.60, with condenser temperatures (network side) of 20-30 °C and evaporator temperatures (user side) of 13-18 °C.

These limits can be overcome by using proper recirculation circuits. This can be implemented with a bypass circuit regulated by a 3-way valve, which allows to mix the water coming from the network with the outlet water of the heat pump. In heating mode, this allows to use a higher temperature network (by lowering it with the heat pump outlet water). The contrary holds for cooling mode. While this widens the range of admissible temperatures for the network (thereby enhancing its possible use as thermal storage or its supply-return temperature difference), it does not affect much the heat pump performance, as the COP is given by the temperatures of the fluid in contact with the machine (i.e., within the recirculation loop rather than within the network, if recirculation is applied).

Reverse operation. The use of reversible HPs allows substations to be used also in cooling mode. However, the practical details of this implementation are different in the 1-pipe and in the 2-pipe case.

In the 1-pipe option for the network, the connection circuit with the heat pump can operate always in the same mode. The corresponding circulation pump draws water from the network and the HP absorbs or rejects heat to this fluid according to the substation needs. In particular, a single network temperature has to be considered at each substation (though different substations in series can experience different temperatures). See top panel of Figure 7.

In the 2-pipe option for the network, instead, different temperatures at the supply and return pipes are available. From the point of view of HP performances, the most convenient solution would be to draw water from the warmer pipe in heating mode and from the colder pipe in cooling mode. In practice, however, some limitations are present. The first and most important limitation concerns the possibility to reverse the flow. Indeed, in the 2-pipe option one can assume that a pressure difference between supply (warmer) and return (colder) pipes is kept by a centralized pump, similarly to traditional district heating. This could drive the flow across the substation in heating mode. When working in cooling mode, in order to draw water from the colder pipe, a local pump acting against the network pressure should be present. This could be installed in a parallel circuit, with proper on/off valves, see central panel of Figure 7. The alternative could be to keep always the same flow direction in the circuit between the network and the heat pump, thereby operating the heat pump under less favourable conditions, see bottom panel of Figure 7. In other words, in the first type of connection one would need a hydraulic pump operating against the network pressure, in the second type one would operate the heat pump against the network temperature. The latter solution would also give rise to supply and return temperatures mixing, whose feasibility depends on the overall balance of the network (similarly to the 1-pipe case). Summarizing:

- The 1-pipe network solution allows for a relatively simple connection between the substation and the network. Indeed, there is no need for flow reversal. Still, a circulation pump is needed, as the 1-pipe network cannot provide the pressure difference to drive the flow across the substation. Moreover, it has the drawback of introducing a variable temperature along the network, putting different substations in different operating conditions (i.e., different COP). The fact that a substation affects the downstream network temperature has to be analysed mainly in winter, where operation in heating mode is expected to be largely dominant. It could be a minor problem in summer for a system with a significant need of cooling, where the temperature variation caused by a substation operating in cooling mode could be compensated by that of a substation operating in heating mode for hot water production.
- The 2-pipe network solution needs more complex or simpler substation solutions, depending whether flow reversal is required or not. If no flow reversal is required, then operation can

work as in traditional substations, with flow driven by the network pressure difference. This avoids even the need of a local circulation pump. However, this comes at the price of a disfavoured operation in cooling mode (or in heating mode, in the uncommon case of a network privileging cooling). If instead flow reversal is required, then both a circulation pump and a reversible flow meter are needed (or two flow meters installed on the two parallel branches). Performance can hence be optimized, but only introducing more equipment.

Note, however, that the considerations about supply-return reversal to optimize the heat pump performance have to be combined with the operational limits of the machine. In practice, if the warm pipe has a suitable temperature to operate the HP in heating mode, for typical machines the cold pipe results too cold to operate in cooling mode. Apart from the possible use of recirculation options, for standard HPs one can than expect that flow reversal is not useful[8]. A last option can be a combination of 1-pipe and 2-pipe: 2-pipe connection in heating mode, 1-pipe connection in cooling mode (drawing water from the warmer pipe and re-pumping it to the same pipe). The potential variety of connections is summarized in Figure 8, in order to help visualizing the possible solutions.

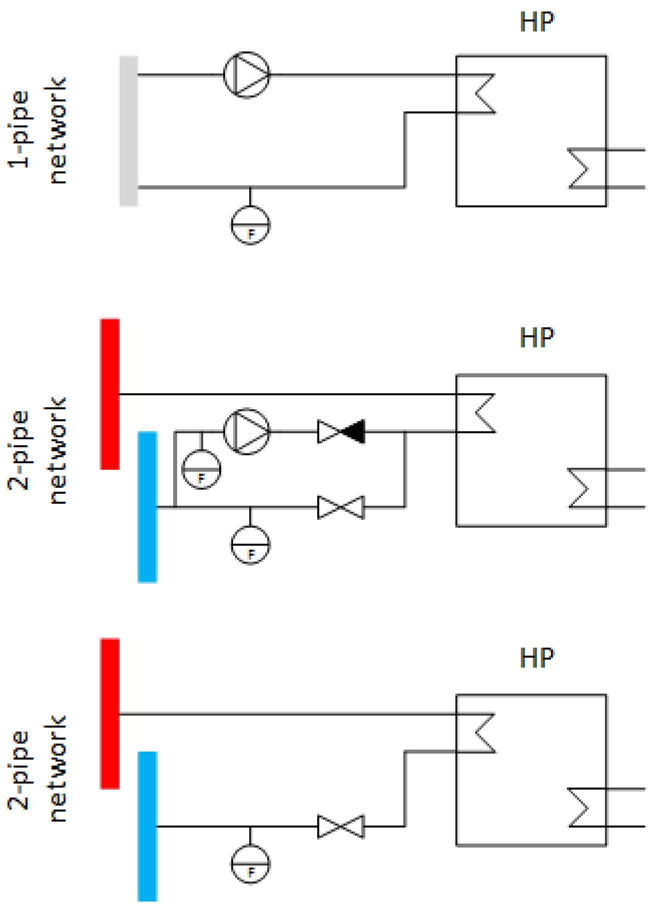

Figure 7. Possible configurations for the connection between the network and the heat pump in the 1-pipe (top panel) and 2-pipe (central and bottom panel) network cases. No recirculation option considered here.

[8] It is also worth pointing out, that common HPs do not accept flow reversal.

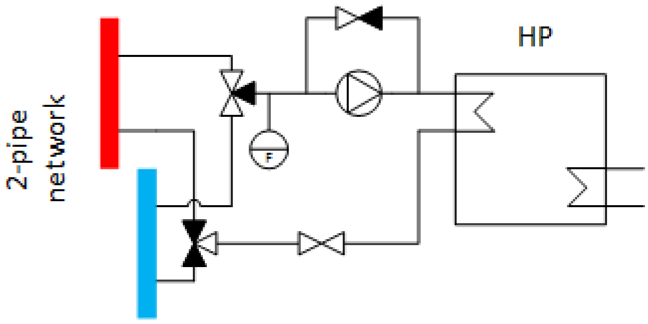

Figure 8. Flexible configuration, yielding the possibility to implement any combination of connection between the inlet and the outlet of the HP and the supply and return pipes of the network. For explanatory purposes only (see text).

Once recirculation is introduced, even more combinations are possible. Assuming to have a supply and a return pipe in the network, as in the 2-pipe case (the 1-pipe case can be considered as a subcase of this classification), one has the following choices[9]:

- Operation mode (OM): heating or cooling (H/C).
- HP inlet pipe connection (In): either to the supply or to the return network pipe (S/R).
- HP outlet pipe connection (Out): either to the supply or to the return network pipe (S/R).
- Recirculation solution (Rec): yes or no (Y/N).

Some of the arising cases are unrealistic, but, due to the operational limits of HPs, some unexpected options might be considered. An example is given by the combination without recirculation mentioned above: heating mode implemented drawing water from the supply/warm pipe at 20 °C to the return/cold pipe at 15 °C, cooling mode implemented drawing and returning water to the same warm pipe at 20 °C (due to the fact that the cold pipe is too cold to run the HP in cooling mode).

4.3 Residential load profiles

In order to estimate network performances, it is crucial to consider proper user load profiles. In the case of traditional DH, detailed load profiles are replaced by load duration curves. An example of a load duration curve is reported in Figure 9.

In the case of FLEXYNETS, it is expected that an hourly analysis is much more important than for traditional networks. Such an analysis is indeed crucial to manage performance and cost variations, as well as to include interactions with the electric grid. Therefore, a specific attention to the evaluation of load profiles was applied in the project, as discussed in Deliverable D2.1.

[9] An additional possible choice (Y/N) could be the introduction of a free heat exchanger, like in free cooling. Moreover, in principle one could distinguish between the cases where the network supply pipe is warmer or colder (difference between heating-biased or cooling biased networks). These options are not considered here.

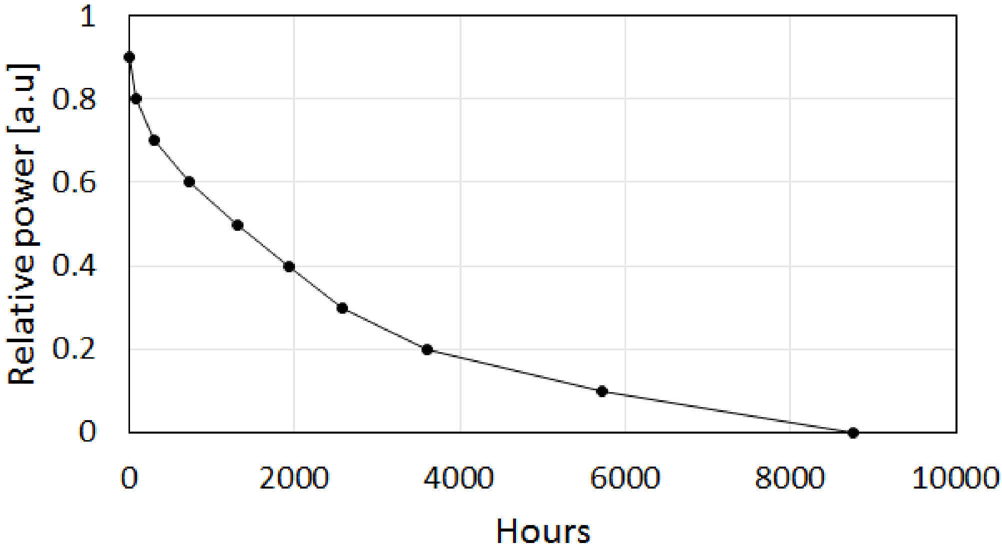

Figure 9. Typical load duration curve. Power is normalized to the yearly peak power.

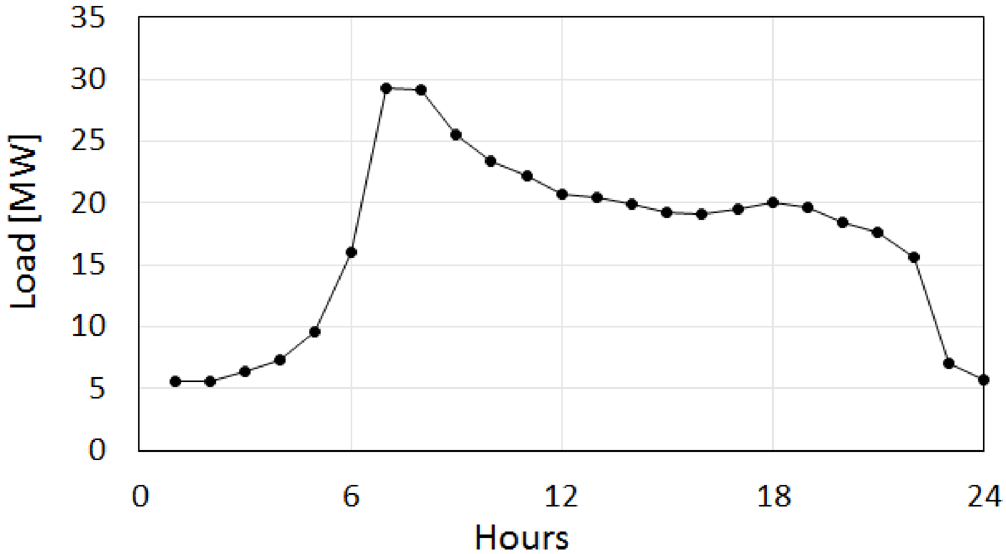

Figure 10. Example of a district heating profile for 1 day. One recognizes a rather sharp peak in the morning and significant smaller consumptions during the night. A large number of conventional residential substations is expected to give rise to an aggregated profile of this type.

For residential substations, detailed load profiles for the heat pump operation were obtained from WP2 and then used in WP3 for simulations. A set of profiles was generated with small random variations, including cooling profiles. In general, it was observed that the resulting aggregated profiles were flatter than what found for traditional substations (reported in Figure 10). This is reasonable, in accordance with the qualitative expectation that HPs should be operated for longer times and lower power with respect to boilers (as favoured by the presence of local thermal storage).

5 Power supply substations

Power supply substations clearly have a strong influence on the network. They are big units involving thermal power values corresponding to a large number of residential substations. As in the previous section, before considering cases specific for FLEXYNETS, a brief review of traditional systems is presented. Some comments about thermal storages are included as well.

5.1 Traditional power supply stations

Traditional networks typically include two broad categories of power supply plants: base load plants, and peak load plants. The first category includes power stations which provide heat at a low operating cost but with low flexibility (e.g., limited or slow modulation of the supplied power), while the second category provides heat with high flexibility but high operating cost. Under the first group one finds for example CHP systems or waste incinerators, under the second group one mainly finds natural gas boilers.

From the point of view of the connection with the network, all these systems work in a simple way: one or more large heat exchangers absorb the supplied heat and transfer it to the network. Base load plants tend to operate at a constant power, while peak load plants have a finer control which modulates their output (e.g., modulating the burner in natural gas boilers) according to the network demand.

The different cost of power supply resources implies a clear priority between them. Indeed, it is of course convenient to minimize the operation time of costlier plants, covering as much demand as possible with the cheaper units. In order to avoid the intervention of peak load units, compensating systems can be combined with base load plants, to cope with the limited flexibility of the latter. While some effect can be obtained with small variations in the network temperature, the most effective solution from this point of view is the installation of thermal energy storages (TES), like for example insulated steel tanks. These systems are often rather large (a few thousands of cubic meters) and can balance the network on time scales ranging from a few hours to about one day. This is defined as short-term storage, as opposite to long-term storage intended as seasonal storage. More details about storage can be found in deliverable D2.3.

An interesting solution already existent in traditional networks and much related to FLEXYNETS is the heat recovery through large heat pumps. Here, the low-temperature heat rejected from large facilities (e.g., chillers for food refrigeration in storehouses) is supplied to the network (typically to the return pipe) thanks to high-temperature HPs, like CO_2 heat pumps. These machines can raise the temperature even up to the supply temperature of 3rd generation networks (i.e., about 90 °C). Actually, depending on the initial temperature of the waste heat, more HPs in cascade can be used. This solution is complementary to the FLEXYNETS approach: while in the FLEXYNETS concept energy is “pumped” to a useful temperature directly at the customer dwellings through many small HPs, in this traditional approach a higher temperature is achieved at some generation points through a few large HPs. The convenience of one solution with respect to the other clearly depends on the overall composition of the network sources and sinks (see discussion in the section about network balancing).

A last comment is in order for solar district heating systems. The introduction of these systems is relatively recent, so that they can still be considered innovative rather than traditional in most countries. However, they can be directly integrated in traditional networks. Here, large flat plate collector fields are typically used, in some cases in connection with seasonal storage, in order to exploit the large availability of solar heat in summer. A few networks based on this solution are currently being operated in Denmark, with solar fractions easily reaching 30-40 %.

5.2 FLEXYNETS power supply substations

In the FLEXYNETS case, the overall distinction between base and peak load plants can be maintained. However, as discussed in deliverable D4.1, a more substantial distinction between balancing (schedulable) and non-balancing (non-schedulable) plants can be introduced. Moreover, the number of non-balancing plants is expected to be significantly larger than in the traditional case, giving rise to a distributed generation system. In the absence of this condition, implying the availability of large amounts of low-temperature waste heat, the entire concept of FLEXYNETS is expected to be disfavoured, unless special heat resources are available (e.g., geothermal or lake energy).

As far as balancing plants are concerned, not much difference is expected with respect to the traditional case. For example, these can still be modulating gas boilers able to adapt to the demand in a flexible way. The only difference possibly introduced by the FLEXYNETS approach could be related to the plant sizing. In principle, with a large number of well-distributed non-balancing sources and an appropriate storage system[10], it could be not necessary to size the balancing plants directly on the overall demand. On the other hand, some oversizing for backup reasons (also considering maintenance issues) could still be desirable, until a very large number of historical data could prove the contrary. Moreover, as it will be seen in Chapter 6, the cost of these backup units is rather small compared to the overall investment cost of a FLEXYNETS network.

Concerning non-balancing units, instead, the FLEXYNETS approach would allow to integrate sources not directly usable in traditional networks. While uncommon sources could then be exploited, their connection with the network is again expected to use common heat exchangers and therefore the connection layout does not need a dedicated discussion. Moreover, non-balancing sources are operated according to internal logics (i.e., independently of the needs of the network). They can hence be considered more “decoupled” from the network than balancing units and their analysis does not need to be carried out “together” with that of the network. Nevertheless, some notable cases are reviewed below, where some peculiarities related to the use of these sources are pointed out.

5.2.1 Ground source heat

These types of sources (comprising vertical boreholes or horizontal piping solutions) have been found to be already exploited in a few tens of cold DH networks across Europe. The problem of how to integrate them with other low-temperature sources has been considered, as their operating temperature (0°C to 10°C) is lower than the design temperatures targeted in FLEXYNETS. Control solutions introducing proper dispatching of the different sources could yield promising compromises in terms of operating temperatures, avoiding to always lower the network temperature to that of the coldest source. This type of integration is considered in the Early Adopters cases studies, Deliverable D6.5, where however a simple parallel operation between ground sources and low-temperature waste heat is considered. It is also worth pointing out that, from the point of view of operating temperatures and concept, solutions based on water basins – like sea, lake, rivers – are very similar to ground source heat. All of these solutions are known in the context of cold district heating and are not further discussed here.

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[10] Thermal storages can be considered part of the balancing system.

5.2.2 Low-temperature urban waste heat

The main examples of low-temperature urban waste heat sources are given by shopping malls, data centres, and commercial buildings with specific cooling needs. Other activities can be identified, ranging from laundries to wineries. Due to their large diffusion, special attention is here given to shopping malls and supermarkets. In particular, a discussion about the availability of waste heat from shopping malls is provided below, including estimates of representative daily and seasonal profiles. This information was mainly retrieved from the CommONEnergy project (see reference EU FP7 CommONEnergy, 2017) and substantiated by other literature references and by direct contacts with existing facilities (see also Deliverable D6.5, about early adopters feasibility studies). Since the behaviour of this type of waste heat source is not widely known, a relatively detailed overview is reported below, with additional comments available in Appendix D.

Three questions were considered concerning shopping malls within FLEXYNETS: (i) how many shopping malls are typically available in the urban context, (ii) how to roughly estimate the yearly heat available from a shopping mall as a function of its size, and (iii) which is the typical time profile of this waste heat. This type of information is useful in order to carry out simulations and general estimates on network balancing. To answer these questions, an analysis of the following steps was tackled:

- Typical number and size of shopping smalls within the urban context.
- Typical energy consumptions of shopping malls.
- Typical time profile of energy consumption.
- Amount of recoverable energy.
- Potential impact on the residential energy demand.

The number of shopping malls per city is interesting for the estimation of the possible FLEXYNETS overall impact. On the other hand, single networks could be located just close to a single shopping mall, thereby exploiting a share of low temperature heat much higher than the typical city average.

In the following, the above points are considered one by one. This analysis is focused on shopping malls (centres including different types of shops) rather than on supermarkets, though from the point of view of heat recovery also small/independent food shops are of interest. In practice, the estimated overall amount of waste heat is expected to be a subset of the available one.

For completeness, it is useful to recall the typical shopping mall classification according to the International Council of Shopping Centers (ICSC) (see references RSE, 2011, and EU FP7 CommONEnergy, 2017):

- Small shopping mall: 5000-20000 m^2 of gross leasable area (GLA).
- Medium shopping mall: 20000-40000 m^2 of GLA.
- Large shopping mall: 20000-80000 m^2 of GLA.
- Very large shopping mall: > 80000 m^2 of GLA.

One category is typically added, namely:

- Neighbourhood centre: < 5000 m^2 of GLA.

As an example, Italian data were retrieved from (RSE, 2011). These data include also neighbourhood centres, which however represent only 3 % of the considered GLA. Consequently, the average figures reported by RSE can be considered fairly representative of the Italian shopping mall sector, in spite of the inclusion of shops outside of the strict shopping mall classification.

The following analysis will not distinguish between the above typologies of shopping malls and will only provide average figures.

- Typical number and size of shopping smalls. It is possible to get general data about the number of square meters per inhabitant (m^2/inhab). In this way, one can get a rough estimate of the total amount of shopping mall area in a city. The considered Italian survey (RSE, 2011) reports an average shopping mall density d_{SM} of about 0.3 m^2/inhab.
- Typical energy consumptions of shopping malls. These consumptions differ depending on the actual type of shops included in the mall. It is however possible to rely on general statistic about shopping mall composition. According to the CommONEnergy project (EU FP7 CommONEnergy, 2017), one has that:
  - Food shops exhibit much larger energy consumptions than other shop types, due to refrigeration. From the point of view of waste heat, they provide the most interesting application. Food shops cover on average a fraction f_{food} = 20 % of the GLA of shopping malls. In food shops, about 50 % of the consumptions are due to refrigeration, 25 % to lighting, 20 % to HVAC (of which about 25 % is used for ventilation), 5 % to other needs (e.g., lifts). The overall consumption is in the range 500-1000 kWh/(m^2·a). Consequently, the refrigeration consumption (electric only) is of the order of 250-500 kWh_e/(m^2·a). The cooling consumption can vary significantly, it can be basically zero in some regions, but it can reach 10-15 kWh_e/(m^2·a) in Mediterranean countries. Cooling consumptions are anyway much smaller than refrigeration ones (moreover they exhibit much more seasonality).
  - Other shops do not include refrigeration, but they are otherwise more or less similar to food shops. Therefore, one has that 50 % of energy consumptions are due to lighting, 40 % to HVAC, 10 % to other needs. The overall consumption is typically of the order of 250 kWh/(m^2·a).
- Typical time profile of energy consumption. Some hypothetical profile is provided by JRC (2013), see Figure 11. Qualitatively, one has that refrigeration consumptions are rather constant (with a small difference between day and night). Conversely, HVAC and especially lighting consumptions have a strong difference between day and night. Opening (or at least occupancy) hours are typically in the range 12-16 hours. While it would be recommendable to modulate HVAC consumptions according to occupancy, in practice this is typically not done. Therefore, for general estimates the following can be assumed:
  - 12 occupancy hours, from 8:00 to 20:00.
  - Refrigeration. Constant load equal to peak load during occupancy hours, reduction of 20 % during closing hours. See however also Figure 12 and Figure 13 (Bacher, 2013).
  - Lighting. Constant load equal to peak load during occupancy hours, no load during closing hours.
  - Heating and cooling. Constant load driven by daily average outdoor temperature during occupancy hours, reduction of 50 % during closing hours.
  - Ventilation. Constant load equal to peak load during occupancy hours, no load during closing hours.

- Amount of recoverable energy. Refrigeration systems have a COP (for waste heat) of the order of 3-5 depending on the return temperature. For FLEXYNETS temperatures, an average COP of 4 seems to be achievable (though the simulation data taken form the CommONEnergy project suggest that a value of 3 is more realistic, see below). Cooling systems have a rather low COP (e.g., in the range 2-2.5) when using air-based HPs, but they could again reach a COP of 4 in a FLEXYNETS application. Concerning the fraction of recoverable energy with respect to the available waste energy, η_{rec}, one can make estimates based on different assumptions. In the absence of local reuse, nearly all the waste heat could be recovered by the network. In the presence of local reuse, lower amounts could be absorbed by the network, possibly with a significant seasonal dependence.

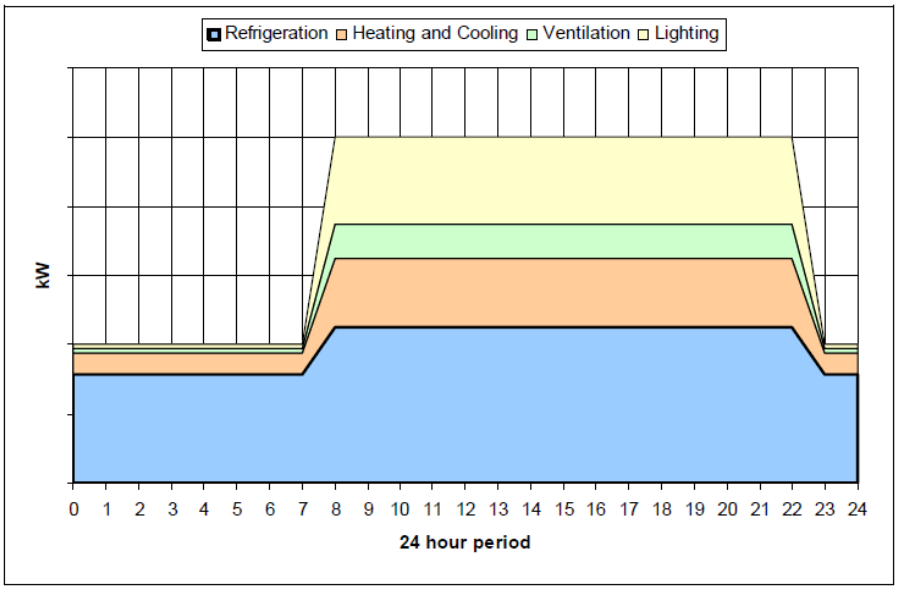

Figure 11. Hypothetical daily consumption of a representative European food retailer store (JRC, 2013).

From a general energy balance point of view, one can conclude the following:

- Assuming a residential heating consumption of the order of 100 kWh/(m^2·a) – a reasonable order of magnitude for relatively recent buildings – and assuming an average dwelling occupancy of 0.025 inhab/m^2 (i.e., 2.5 inhabitants for a dwelling of 100 m^2; this is reasonable according to Eurostat data[11]), one gets 4000 kWh/(inhab·a). This of course depends on the geographical zone and on the building type. Similarly, one can estimate cooling consumptions, which for Mediterranean countries (e.g., Italy) can be of the order of 10 % of heating consumptions (as thermal energy).

- As reported above, refrigeration consumptions are much higher than cooling ones (about 20 times). On the other hand, refrigeration is present only in food shops, which cover roughly 20 % of shopping mall GLA. Taking into account only this fraction of waste heat, one gets 20 % × 500 kWh/(m^2·a) × 50 % (fraction of refrigeration electricity consumptions) × 4 (COP) = 200 kWh/(m^2·a). One then can apply different recovery factors, η_{rec} = 90 %, 50 %, 10 %. At 90 %

[11] Eurostat, data for Italy: 30 % share with 1 person per flat, 27 % share with 2 persons per flat, 41 % share with 3-5 persons per flat, 2 % share with more; the average dwelling size is 90 m^2 in cities, 100 m^2 outside.

recovery one gets 180 kWh/(m²·a) and converting into consumptions per inhabitant with d_{SM} = 0.3 m²/inhab one gets 600 kWh/(inhab·a). This is 15 % of the above residential consumptions. Note that however, while refrigeration consumptions are rather constant during the year, residential heating consumptions are concentrated in winter. A seasonal storage would hence be needed to reach this high recovery factor. At 50 % recovery one would get 100 kWh/(m²·a) = 333 kWh/(inhab·a), which is about 8 % of the above residential consumptions. Finally, at 10 % recovery one would get 20 kWh/(m²·a) = 67 kWh/(inhab·a), which is about 1.7 % of the above residential consumptions.

Of course, for small thermal grids located nearby shopping malls this share could be higher.

Finally, as far as time profiles are concerned, apart from daily fluctuations, a rather constant availability throughout the year can be assumed (see Appendix D for a more detailed discussion).

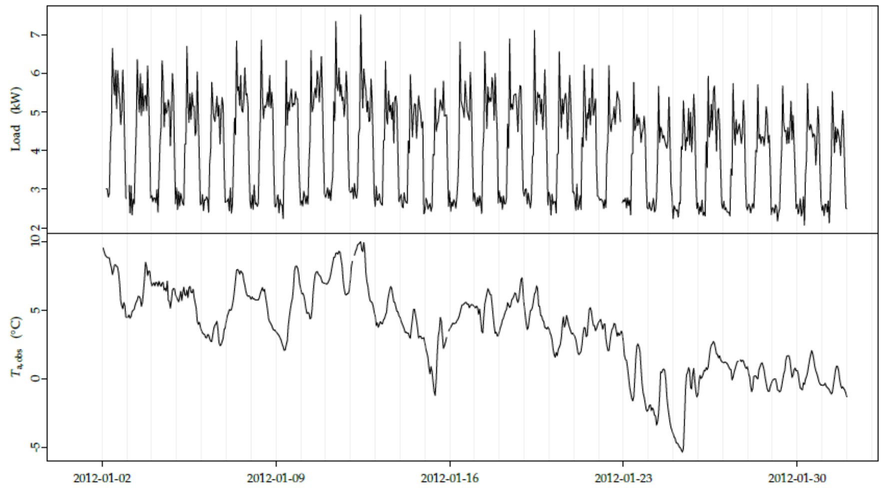

Figure 12. Example of time series (load and temperature) for winter (January, Denmark), taken from (Bacher, 2013).

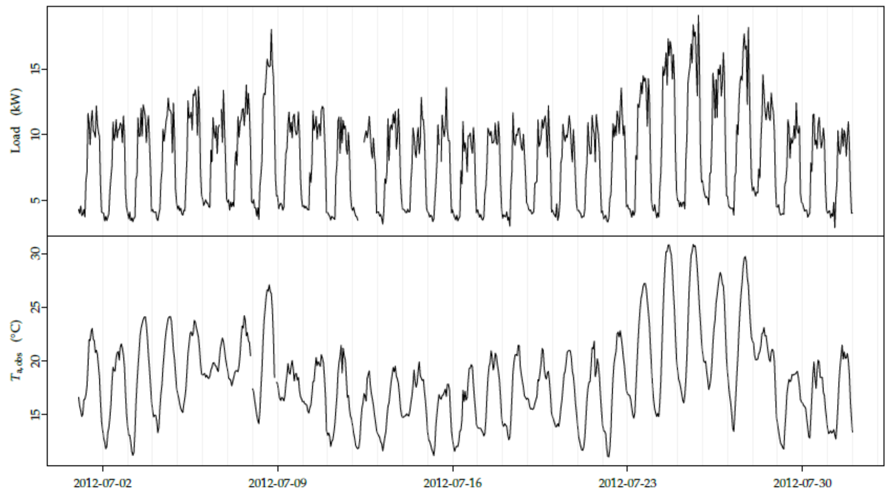

Figure 13. Example of time series (load and temperature) for summer (July, Denmark), taken from (Bacher, 2013).

5.2.3 Solar thermal energy

Solar thermal energy is usually exploited in DH through flat plate collectors. This is the solution advocated in solar district heating (SDH). In FLEXYNETS, two different options have been considered. One still concerns flat plate collectors, though used at lower temperatures: it can be seen that, under suitable conditions, the corresponding increase in the efficiency can compensate the electricity consumptions introduced by HPs. The second option concerns concentrating solar power, where concentrating collectors (e.g., parabolic trough collectors) are coupled to a suitable thermodynamic cycle (an ORC engine). This option – basically providing the FLEXYNETS analogue of a conventional CHP – has been found to be usually too expensive, mainly not due to the cost of the solar field, but due to that of the ORC engine. The latter can be paid back in a reasonable time only with a high number of operation hours, which the solar field cannot guarantee as a standalone generator. A possible solution is however the joint operation with a biomass boiler, thereby extending operation with a fossil-free source. The corresponding increase in investment costs is not dramatic. Hence, for covering a base-load with a large number of operation hours, in principle one can identify conditions where this solution is economically sustainable. Corresponding requirements are however quite peculiar, and this option is not considered the most promising one. These aspects are discussed in detail in the paper D'Antoni et al. (2018). A short summary of its results is reported below, focusing on the relevance for the FLEXYNETS concept.

Flat plate collectors (FPC). The efficiency of FPC can be approximated by the expression $\eta_{FPC} = \eta_0 - a_1(T_f - T_{amb})/G_T - a_2(T_f - T_{amb})^2/G_T$, where G_T is the global irradiance on the collector plane, T_f is the average fluid temperature, and T_{amb} is the external temperature. The values of the remaining coefficients depend on the specific collector model. As an example, we report here the values of a collector used and monitored within the InSun project (see the references EU FP7 InSun, 2015, and D'Antoni et al., 2018), where η_0 = 0.811, a_1 = 2.71 W/(m^2·K), and a_2 = 0.01 W/(m^2·K^2). In order to operate these collectors with a conventional 3rd generation DH network one would need $T_f \simeq$ 70 °C (supply-return average temperature). Assuming an average external temperature of 15 °C and a peak radiation of 1000 W/m^2, one gets an efficiency of about 63 %. Reducing the average fluid temperature to 20 °C, efficiency would reach about 80 %, with a relative increase of 27 % in the energy output. According to the cost assumptions reported in D'Antoni et al. (2018), the levelized cost of heat for an installation in the Rome climate would be of the order of 27 €/MWh, rather high for a low-temperature source, but lower than the cost of gas. Due to the additional electricity consumptions (order of 20 % of the useful energy for an average COP of 5), this solution is typically not expected to be more convenient than high-temperature solar district heating as a stand-alone system; but in cases where FLEXYNETS is made convenient by the presence of large shares of cheap low-temperature waste heat, an integration of solar energy through flat plate collectors – aside intermittency aspects – appears to be more convenient than gas.

Parabolic trough collectors (PTC). In the case of concentrating collectors, efficiency is typically calculated in terms of the direct normal irradiance (DNI) rather than the global irradiance. Moreover, one has to include the incident angle modifier (IAM) which takes into account the remaining misalignment with the sun for 1-axis tracking systems. Efficiency is hence typically expressed in the form $\eta_{PTC} = \eta_0 \mathrm{IAM} - a_1(T_f - T_{amb})/\mathrm{DNI}$, where non-linear terms in the temperature difference are neglected. With these collectors, temperatures well above 200 °C can be easily reached, making them suitable for cogeneration with ORC engines, as described in Deliverable D2.1. However, ORC machines involve high investment costs and in order to give rise to reasonable payback times require a large number of operating hours, of the order of 3000-4000 h/year. This is of course much higher than solar energy can offer, unless storage (very expensive at high temperature) is included. A possible solution in order to obtain an economically profitable system is hence to couple the solar field with a boiler. This can increase the number of operation hours, provided a matching load exists. Usage of biomass as a fuel would preserve the system renewability. As discussed in D2.1 and in D'Antoni et al. (2018), at the moment acceptable payback times can be obtained only in special cases. On the other hand, the opening of a larger market could help in lowering costs for these technologies, making them still relevant for the future.

As mentioned above, this solution closely resembles that of a CHP plant. Here, however, a key role is played by renewable energy. The rationale behind this type of power supply substation can be summarized in the following points:

- Solar energy is included because the FLEXYNETS concept requires a significant amount of renewable (or at least "free") energy to be sustainable. If all the energy were provided by fossil fuels, there would be no sense in using heat pumps (they would only introduce additional primary energy consumptions with respect to a direct use of fossil fuels).
- It is interesting to investigate the potential for replicating the CHP concept with solar energy, possibly enhancing the renewable potential of district heating and cooling. In order to simultaneously produce electricity and heat from solar energy, concentrating collectors/mirrors are needed. In this way it is indeed possible to reach temperatures high enough to run thermodynamic cycles[12]. The ideal candidates for the exploitation of medium-temperature heat are ORC engines[13]. Still, in order to obtain reasonable efficiencies, also the cooling temperature of the engine must be kept as low as possible. Hence, the integration with a neutral temperature network is more favourable than with a traditional network.

Within T2.1, the considered power supply substation includes other possible components (e.g., a back-up boiler). The ideal composition of this substation and the sizing of the different components are investigated within that task. Here, however, some general remarks related to the interaction with the network can be reported.

Similarly to a traditional CHP plant, this solar-supplied ORC system cannot be considered very flexible. It is hence a non-balancing unit most suitable to cover the base load of the network. However, in this case the economic profitability of the system is expected to be reduced with respect to a conventional CHP. From this point of view, the number of yearly operation hours is clearly crucial, in order to recover the large investment costs of this system. One can split the substation in two sub-units, the concentrating solar field and the ORC engine.

- Concentrating solar field. From an economic point of view, the levelized cost of energy of this source should be compared at least with the price of natural gas (though in some cases CHP can be connected with even cheaper energy sources, as in the case of high-temperature industrial waste heat). Considering typical costs of collectors and assuming a certain lifetime, one can derive a minimum number of yearly operation hours in order to be competitive, making a strong selection in terms of feasible locations.
- ORC engine. Economically, the reference values are here given by the prices of electricity and low-temperature heat (expected to be different from that of heat at higher temperatures). Assuming that the solar field can stay competitive with natural gas, one can calculate the levelized cost of energy for the ORC as a function of yearly operation hours and plant

[12] Considering the low temperatures of a FLEXYNETS network, in principle also heat recovery from PV plants could be considered, yielding a different cogeneration concept. However, though several studies on PVT (photovoltaic plus thermal) systems are available in the literature, commercial success is not yet achieved so far and this option is not analysed here.

[13] For very efficient concentrating mirrors, temperatures can be high enough for other thermodynamic cycles. For medium temperatures, also Stirling engines were considered, though so far with little commercial success.

lifetime, again obtaining minimum requisites for its competitiveness, as discussed above. If the economic feasibility of this system requires a number of yearly operation hours greater than the available operation time from the solar field, a backup system can be considered.

There is of course some freedom to allocate costs and revenues of these systems, again similarly to what happens for CHP. For example, one could accept an ORC engine with a slightly worse cost-performance ratio in cases where the solar resource would be more competitive than the minimum threshold. One could also accept a slightly higher electricity generation costs in cases where the heat generation cost would be more competitive. Different strategies can be pursued according to specific cases.

Of course, besides economic considerations also environmental considerations should be included. The latter can be roughly taken into account from an economic perspective considering the current framework of incentives (e.g., white and green certificates, feed-in tariffs). A detailed discussion is not presented here (as the value of incentives is currently not very high), but should of course be considered in a practical feasibility study.

Independently of the actual result of these analyses (see D2.1), it is clear that the connection with the network is a minor issue in this context. Conditions to be considered could however be related to the ownership of the plant or the contractual agreements between the plant owner and the network. Indeed, as the economic profitability of this system is expected to be limited, maximising the number of yearly operation hours and hence the plant priority would be crucial. This should be properly taken in consideration when balancing the network.

5.2.4 Industrial waste heat

High-temperature industrial waste heat. In this case, heat can come for example from furnace flue gases. Metal (iron, steel), glass, and brick manufacturing factories are typical examples of industries suitable to this purpose. Clearly, high-temperature waste heat is not peculiar of FLEXYNETS, as it can be exploited in conventional networks as well. On the other hand, its integration in FLEXYNETS is also possible. Since, however, this type of heat is already available at temperatures high enough for space heating and DHW preparation, its use in combination with heat pumps should be evaluated case-by-case. Indeed, as discussed in the previous sections, whenever high-temperature heat is available in proportions larger than low-temperature waste heat, a high temperature network is expected to be more convenient. In this case, low-temperature heat could be integrated (with rare economic convenience) through high-temperature heat pumps. For FLEXYNETS, it is hence more reasonable to consider the case where high-temperature waste heat provides only a minor fraction of the overall supply.

Waste heat profiles of similar applications (which have been collected and made available for simulations) often involve significant daily fluctuations, to be taken into account when designing detailed network control and storage solutions. Their dependence on seasonal effects is however typically negligible. The waste heat profile of an iron melting furnace is shown in Figure 14.

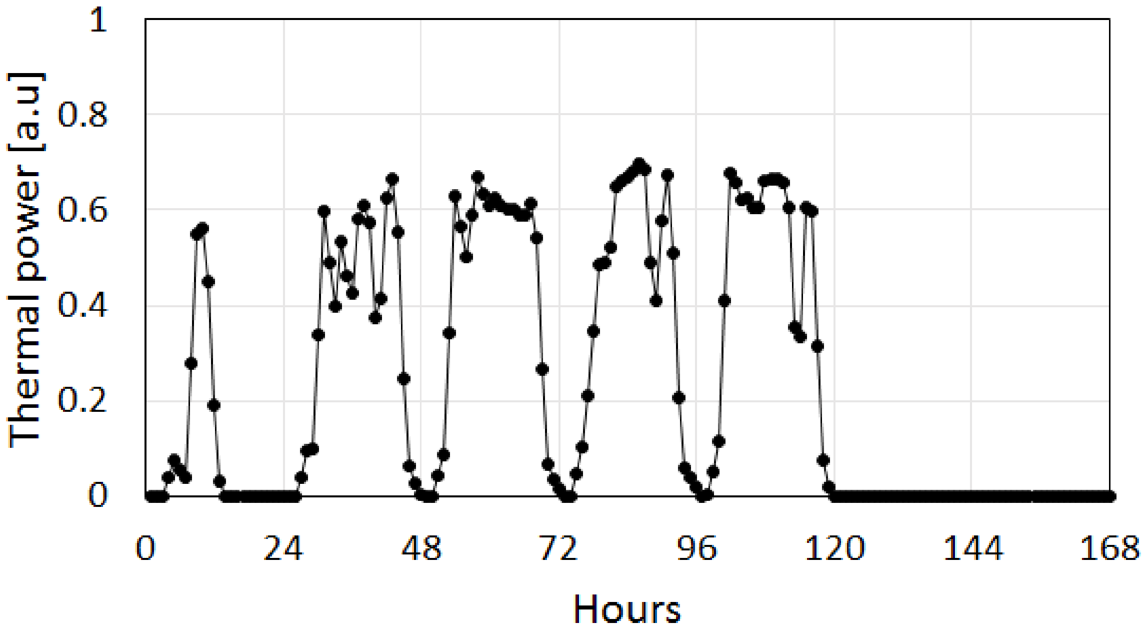

Figure 14. Example of high-temperature industrial waste heat profile. Data from a week of operation of an Italian iron foundry. Nominal schedule is 04:00-20:00 from Tuesday to Friday (16 h/day, 2 shifts, 4 days/week). The plot shows how real data approximately follow the nominal operation, though significant variations occur. Power is normalized to the yearly peak power value.

Low-temperature industrial waste heat. This is the case, for example, of cooling towers. It is worth pointing out that even for factories possibly providing high-temperature waste heat cooling towers are typically present. In some cases, it can be more easier and more convenient to recover heat from these low-temperature systems rather than from processes at higher temperature. Iron foundries might provide an interesting example of this type: the iron melting process is often based on cupola furnaces burning coal and hence giving rise to very dirty flue gases. The high dust content of these exhaust systems – together with the high temperatures – provide a very harsh environment and require rather complicated solutions in terms of heat exchanger technologies. It can be much simpler (and less risky for the production process, favouring the agreement with the factory) to connect to the existing cooling system at lower temperatures, downstream of the well-established cleaning technologies used in this context (cyclones and filters). For factories relying on gas or electric furnaces (like steel manufacturing companies, to remain in the metallurgical sector) heat recovery might be less complicated, but connecting to cooling towers is nevertheless safer from the process point of view.

5.2.5 Summary about heat sources

Summarizing, besides usual high-temperature waste heat sources, four major potential groups of low-temperature sources have been identified: urban waste heat, low-temperature industrial waste heat, solar heat (in the above low-temperature variants), and ground source heat. Existing examples suggest that each of these sources could often provide about 10 % of residential loads. In specific situations, one of them alone (typically ground source heat) could satisfy a high load fraction. Consequently, in order to reach significant low-temperature shares (e.g., order of 50 %) it is expected that several of them have to be combined, confirming the FLEXYNETS concept and the need for suitable high-level control solutions (proper unit commitment and load dispatching, see D4.1).

With the exception of the solar source, it is also worth pointing out that the identified sources typically have relatively constant profiles throughout the year. In spite of daily variations, this is the case for all industrial activities, where production is negligibly affected by seasonality. Similarly, refrigeration needs are present along the entire year, with only a limited increase during summer. In particular, the observed seasonal variations are much smaller than those related to residential loads. As a consequence, in order to carry out simplified analyses about the role of low-temperature waste heat within a FLEXYNETS system, it makes sense to roughly assume constant profiles. This will be done in some of the parametric analyses carried out in Chapter 6.

6 Parametric analysis

The novelty of the FLEXYNETS concept makes it impossible to provide design recommendations and rules of thumb based on practical experiences and real-world applications. Hence, to derive some general guidelines which could be useful for planners and DH utilities for the future implementation of the FLEXYNETS concept, several parametric analyses were carried out, to assess the impact of different design parameters and operating conditions on the feasibility of a FLEXYNETS system.

The parametric analyses were carried out through the Excel pre-design tool developed within the FLEXYNETS project (Deliverable D6.11). Hence, the presented results and conclusions are valid within the assumptions and simplifications made in the above-mentioned Excel tool. For a comprehensive description of how the Excel tool works, it is recommended to read the user manual, available at the FLEXYNETS website.

The following sections present and comment the results obtained from the different parametric analyses. Each section focuses on a single element (e.g., heating and cooling demand, amount of available waste heat, etc.) which can significantly influence the feasibility of a FLEXYNETS network. These separate analyses can be used to understand the role of one effect/variable holding all else constant. Comparisons with conventional DH and/or individual cooling solutions are also presented.

6.1 Typical heating and cooling demand profiles for different locations and different settlement typologies

The feasibility of a FLEXYNETS system was evaluated in different geographical locations and different settlement typologies. The Excel tool requires in input the specific heating and cooling demands, as well as their distribution over the year. These data were retrieved from the substation simulations carried out for Deliverable D2.1 and were already used in the Deliverable D2.3 (about seasonal storages), developed within the FLEXYNETS project.

The above-mentioned profiles return the demand for space heating, domestic hot water and space cooling (SC) of four different settlement typologies in three different geographical locations. The four settlement typologies were[14] existing single-family houses (SFH/EX, 200 m^2 of living area), existing small multi-family houses (s-MFH/EX, 500 m^2), an equal mixing of existing SFH and s-MFH (see below for details), and retrofitted small multi-family houses (s-MFH/45, 500 m^2). The three geographical locations were Rome, Stuttgart and London, representative respectively of Southern, Central and Northern Europe. The yearly heating demand (SH+DHW) and the yearly SC demand of the different buildings are listed in Table 1. As can be seen from the table, existing houses (SFH- or s-MFH/EX) do not have a cooling demand, as they are not equipped with a cooling system.

The yearly profiles of the heating demand are shown in Figure 15 for the SFH/EX buildings. Those for the s-MFH/EX are not shown, as they are largely similar to those of the SFH/EX buildings. The yearly profiles of the heating and cooling demand are shown in Figure 16 for the s-MFH/45 buildings in Rome.

[14] The same abbreviations used in Deliverable D2.1 are used here. Note that the code "45" used for retrofitted buildings refers to the fact that for these houses the insulation level was chosen in order to meet a requirement of about 45 kWh/(m^2·year) of space heating consumptions. The only difference with respect to D2.1 is that here the supply temperature of the HPs is assumed to be 50 °C for both existing and retrofitted buildings. This affects the COP and is commented later in the text. Given these assumptions, "existing" and "retrofitted" are here used as qualitative terms.

The profiles for the s-MFH/45 buildings in London and Stuttgart are not shown, because these cases are not presented in this study, for reasons that will be explained later in this report.

Table 1: Yearly heating (SH+DHW) demand and space cooling (SC) demand for the different settlement typologies and geographical locations.

	Heating (SH+DHW) demand [MWh/year]			SC demand [MWh/year]
	SFH/EX	s-MFH/EX	s-MFH/45	s-MFH/45
London	35.5	94.0	46.9	3.55
Stuttgart	31.3	91.1	43.4	8.34
Rome	19.4	55.2	47.4	21.5

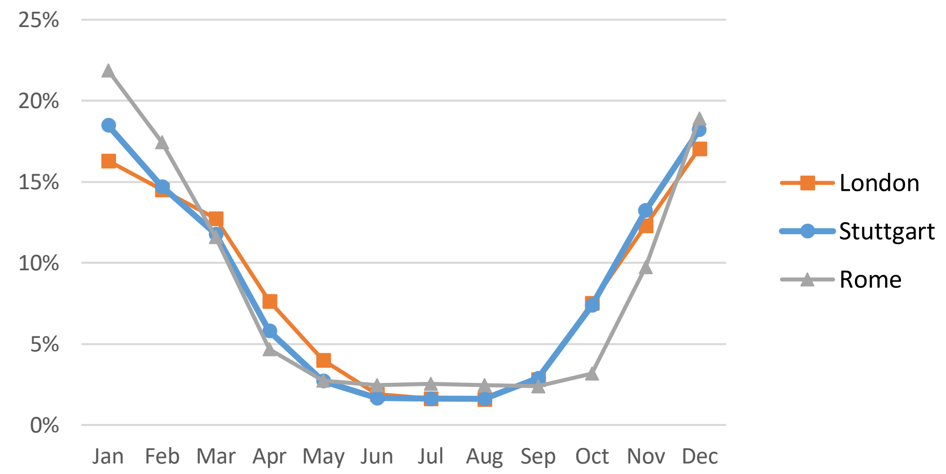

Figure 15: Heating demand profiles in the different geographical locations for the buildings SFH/EX.

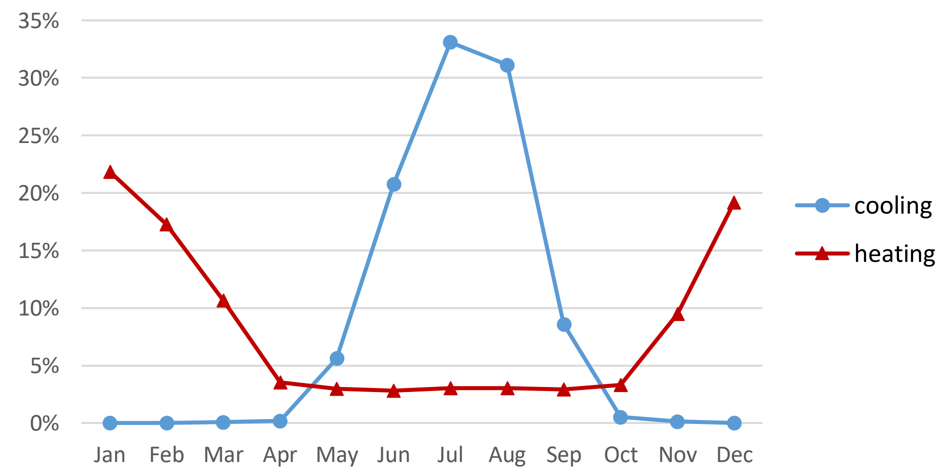

Figure 16: Heating and cooling demand profiles in Rome for the buildings s-MFH/45. Note that demand is reported as a percentage of the yearly demand (considering absolute values, cooling is not higher than heating).

For all the above cases, the overall performance (in terms of costs and carbon emissions) of a FLEXYNETS network was studied. Moreover, this was compared against conventional DH (i.e., 3rd generation DH with high operating temperatures) and, in the presence of cooling demand, against individual cooling solutions (split units). Regarding the daily profiles used in the analysis, the default profiles proposed by the Excel tool for the three different locations were used in case of conventional DH + individual cooling (see D6.11), while in case of a FLEXYNETS system, a constant profile was assumed throughout the day, given the more constant operation which can be expected from a heat pump and the presence of a buffer storage.

The different scenarios investigated in this section — and, unless otherwise specified, also in the other scenarios presented in this study — assumed as input parameters the values listed in Table 2.

Table 2: Main parameters used in the investigated scenarios.

Parameter	**Value**	**Unit**
Total land area	1	km^2
Heating load temperatures	30 - 50	°C
Cooling load temperatures	10 – 15	°C
Interest rate	3	%
Central heater	Gas boiler	-
Price of electricity (private)	200	€/MWh
Price of electricity (industrial[15])	100	€/MWh
Price of natural gas (industrial)	30	€/MWh
CO_2 emission for electricity (see Appendix B)	377	kg/MWh
CO_2 emission for natural gas (see Appendix B)	250	kg/MWh
Safety factor for sizing all components	1.1	-
Conventional DH (3rd generation)		
Network temperatures (supply-return)	80-50	°C
Pipe insulation class	SERIES 3	-
Diversity factor for sizing the heat exchangers	0.6	-
Diversity factor for sizing the cooling machines	0.8	-
FLEXYNETS		
Network temperature (supply)	25	°C
Pipe insulation class	SERIES X	-
ΔT along HP's evaporator (in heating)	10	K
ΔT along HP's condenser (in cooling)	10	K
Diversity factor for sizing the HPs	1	-

As it can be seen, a city area of 1 km^2 was chosen. This corresponds to a relatively large system, where the "aggregated" approach of the pre-design Excel tool is expected to be more appropriate. The energy prices in Table 2 were based on EU-28 averages for the 2nd half of 2017 (Eurostat, 2018a; Eurostat, 2018b; see Appendices for a wider discussion on energy prices).

[15] Here it is assumed that the HPs are owned by the network manager, so that electricity used by the them is paid at a price equivalent to that of industrial consumers. Other business models are possible (in the presence of local PV installations, it could be convenient for customers to own the HPs in order to increase PV self-consumption).

Concerning the network supply temperature, the same value holds for both heating and cooling. Hence, for the given supply-return temperature difference of 10 K, the network return temperature is 15 °C when heating dominates and 35 °C when cooling dominates. Assuming that on the building side the supply temperature is 50 °C for both SH and DHW, one obtains a COP of the order of 4. For a building side supply temperature of 35 °C, the COP would be about 6.2. For different SH and DHW supply temperatures, one can estimate the COP as a weighted average. For example, for a retrofitted building in the Southern Europe climate (particularly relevant for FLEXYNETS due to the presence of cooling) the overall DHW demand is roughly 50 % of the SH demand and assuming SH supply at 35 °C and DHW supply at 50 °C one finds that the overall COP is about 5.5. With a cooling supply temperature of 10 °C, the energy efficiency ratio[16] EER is instead about 4.2.
The scenarios presented in this section investigate the implementation of a FLEXYNETS system in three different locations, under four different settlement typologies:

- Low-density residential area (only SFH/EX buildings) with a plot ratio of 0.10 (see Deliverable D3.1). Based on the living area of a SFH/EX building mentioned above, this results in 500 buildings per 1 km^2 of land area.
- High-density residential area (only s-MFH/EX buildings) with a plot ratio of 0.80 (see D3.1). Based on the living area of a s-MFH/EX building mentioned above, this results in 1600 buildings per 1 km^2 of land area.
- Mixed composition of low- and high-density residential area. It is assumed that 250 SFH/EX buildings and 800 s-MFH/EX buildings are present.
- High-density residential area (only s-MFH/45 buildings, with lower demand than existing ones) with a plot ratio of 0.80. This results in 1600 buildings per 1 km^2 of land area (this case was only treated for the location of Rome).

In each scenario, the heating and cooling demands for the investigated land area of 1 km^2 were calculated simply multiplying the heating and cooling demands of the different buildings (Table 1) by the number of buildings (see bullet list above). However, in the case of high-density residential area with retrofitted houses s-MFH/45 in Rome, three different penetration of cooling were investigated, and the yearly cooling demand was assumed equal to 25 %, 50 % and 100 % of the total cooling demand resulting from the profile (see the cases 10-12 in Table 3). This choice was made to consider that currently not all the buildings have a cooling system.

The numbering, settlement typology and location of the above-mentioned 12 scenarios are listed in Table 3.
For cases 4, 10, 11 and 12, it was also investigated a parallel scenario, where the heating demand was covered by conventional DH and the cooling demand (if present) by individual split units. To avoid misunderstandings, the suffixes “FL” and “DH” after the scenario number denote whether the scenario used a FLEXYNETS system or a conventional DH system.

[16] The energy efficiency ratio is the ratio between the heat extracted at the HP evaporator and corresponding amount of consumed electricity. It is easy to see that with this definition EER = COP-1.

Table 3: Settlement typology and location of the scenarios 1-12.

Case	Settlement typology	Location
1	SFH/EX	London
2	SFH/EX	Stuttgart
3	SFH/EX	Rome
4	s-MFH/EX	London
5	s-MFH/EX	Stuttgart
6	s-MFH/EX	Rome
7	50% SFH/EX + 50% s-MFH/EX	London
8	50% SFH/EX + 50% s-MFH/EX	Stuttgart
9	50% SFH/EX + 50% s-MFH/EX	Rome
10	s-MFH/45 (25 % of cooling)	Rome
11	s-MFH/45 (50 % of cooling)	Rome
12	s-MFH/45 (100 % of cooling)	Rome

The economic feasibility of a FLEXYNETS network was evaluated in terms of equivalent annual cost, which represents the annual cost of owning, operating and maintaining all the components of the system (central plant units, distribution network, heat pumps, etc.). The equivalent annual cost (EAC) is given by

$$EAC = \sum_i P_i + \sum_i O\&M_i + \sum_i (c_{f,i}\, Q_{f,i}) ,$$

where

- EAC [€/year] is the total equivalent annual cost to cover the demands;
- P_i [€] is the annualized capital cost of investment of the system i-th component calculated by the annuity loan down-payment formula, given by

$$P_i = \frac{PV_i\, r}{1-(1+r)^{-n_i}} ,$$

  where

  - PV_i [€] is the present value of the total investment for the i-th component;
  - r [%] is the yearly interest rate (always assumed to be 3 %, as specified in Table 2);
  - n_i [year] is the investment lifetime of component i;
- $O\&M_i$ [€] is the sum of the yearly fixed and variable O&M costs of the i-th component;
- $Q_{f,i}$ [MWh] is the amount of energy (fuel, electricity or waste heat) used by the i-th component;
- $c_{f,i}$ [€ MWh^{-1}] is the price of the energy source/carrier used by the i-th component.

In case of conventional DH + individual cooling, the cost of the system was calculated following the same approach.
It should be noted that, as the equivalent annual cost is not expressed per unit energy (given the simultaneous presence of both heating and cooling in a FLEXYNETS system), it should only be used to compare systems which meet the same yearly demands of heating and cooling (so for example 4FL with 4DH, 10FL with 10DH, etc., and not 1FL with 2FL or 3FL). Anyway, specific heating and cooling costs will be also calculated and reported in tables below.

The diagrams from Figure 17 to Figure 20 show the composition of the equivalent annual cost of the FLEXYNETS systems (*FL* suffix) and of the conventional DH systems (*DH* suffix) in the 12 scenarios listed in Table 3. Table 4 shows the price for heating and that for cooling in the investigated scenarios as well as the total GHGs' emissions of the systems, highlighting the contribution coming from the electricity consumption.

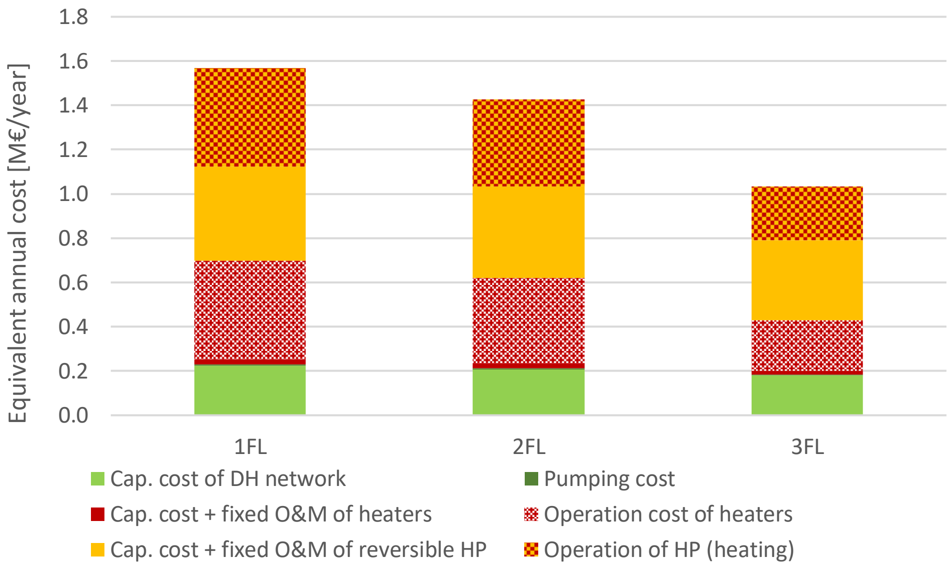

Figure 17: Composition of the equivalent annual cost for the FLEXYNETS systems in the scenarios 1-3, referring to SFH/EX as settlement typology and to the three different locations (London, Stuttgart, Rome from left to right).

As fare as Figure 17 is concerned, the focus is on geographical dependence. The three scenarios all include existing SFH only, but for the three different considered climates. No cooling is present. In practice, the different climates hence reduce to different heat demand densities. No comparison with conventional DH is done here, as it is done for the s-MFH case below. To avoid the inclusion of other effects, only a centralized natural gas boiler is considered as a source. Consequently CO_2 emissions and costs are not really significant as absolute values: here the point is to look at relative changes and comparisons.

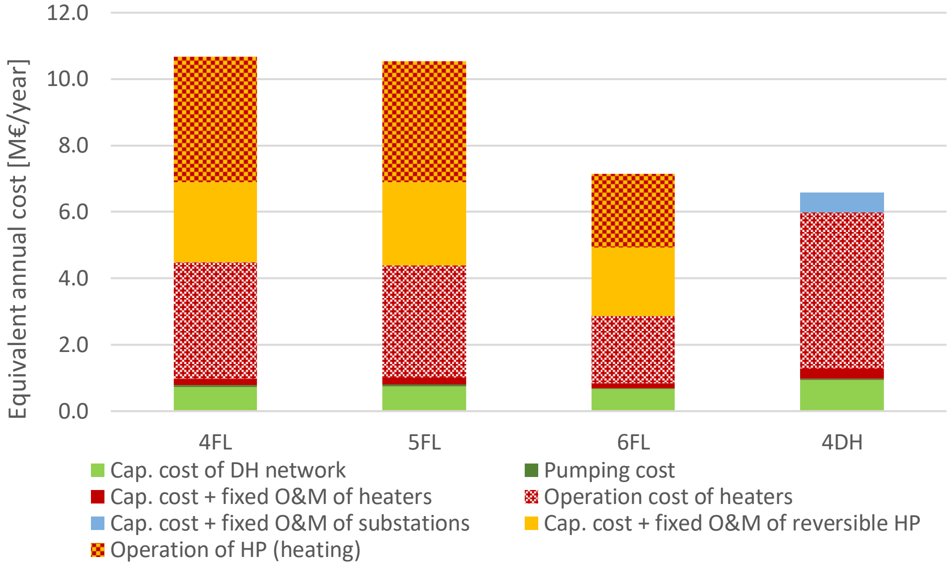

Figure 18: Composition of the equivalent annual cost for the FLEXYNETS systems in the scenarios 4FL-6FL and for conventional DH in the scenario 4DH, referring to s-MFH/EX as settlement typology and to the three different locations (London, Stuttgart, Rome from left to right).

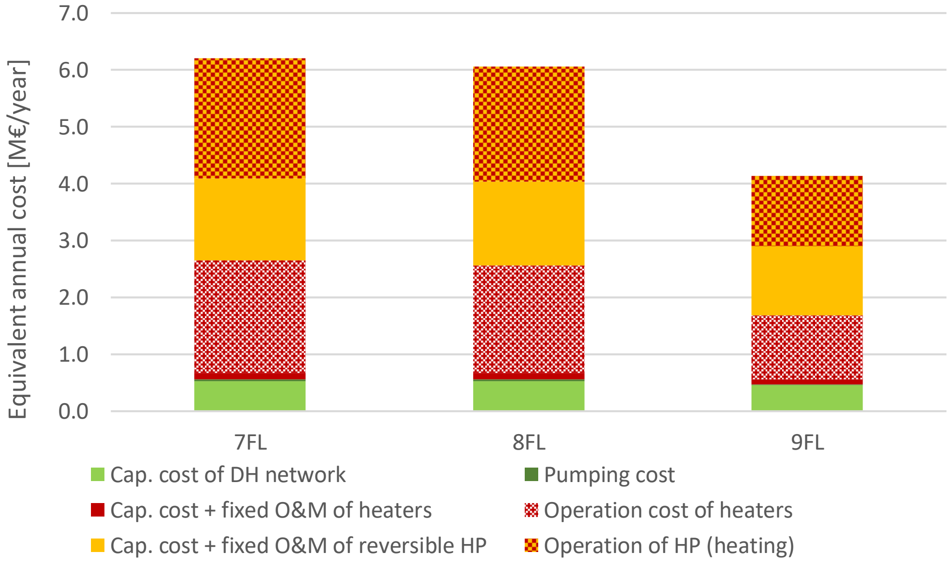

Figure 19: Composition of the equivalent annual cost for the FLEXYNETS systems in the scenarios 7-9, referring to a mixed composition of SFH/EX and s-MFH/EX as settlement typology and to the three different locations (London, Stuttgart, Rome from left to right).

The comparison reported in Figure 18 is similar to that of the previous figure, but considers s-MFH and includes conventional DH. The three scenarios of Figure 19 finally analyse the geographical effect on a mixed building case. Note that by comparing, e.g., 1FL (Figure 17), 4FL (Figure 18), and 7FL (Figure 19) one can see the effect of varying the building stock composition while keeping the same location.

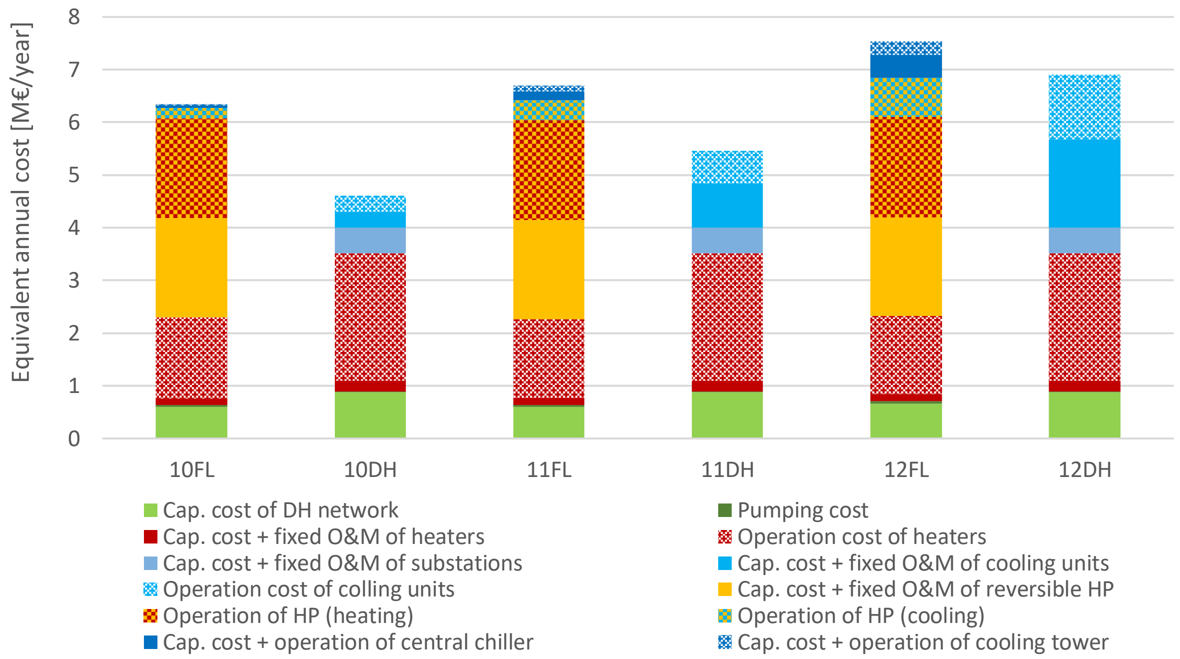

Figure 20: Composition of the equivalent annual cost for the FLEXYNETS systems in the scenarios 10FL-12FL and for conventional DH + individual cooling in the scenarios 10DH-12DH, referring to MFH-RF as settlement typology and to the three different locations.

The six scenarios reported in Figure 20 deal instead with retrofitted (lower demand) small multifamily houses, all for the same location (Southern Europe). Here, the focus is on three different levels of cooling penetration. The comparison for cooling was done against individual cooling based on split units.

While it is evident that for larger cooling demands the FLEXYNETS solutions becomes more competitive, for these cases it never overcomes conventional solutions. A remark is order concerning this point. As it can be seen, very large cost items are given by electricity consumptions for HPs, both for heating and for cooling. However, while the load profiles of retrofitted buildings were used in the calculations, the temperatures on the building side were not optimized for low temperature operation, so that average COP and EER of about 4 were used (see above). In fully retrofitted buildings, proper terminals (e.g., radiant panels, see Deliverable D2.1) allow for milder operating temperatures, so that COP values of the order of 5.5 can be reached. It is easy to estimate the corresponding effect on overall costs: for example, increasing the COP from 4 to 5.5. corresponds to an increase of 37.5 % and hence to the same reduction in electricity consumptions. Looking to scenario 12FL, the electricity costs for heating would then be reduced from 1.9 M€ /year to less than 1.4 M€/year, with a cost reduction of more than 0.5 M€/year. It can be seen that this would be enough to make the scenario 12FL less expensive than the scenario 12DH. A similar increase in the EER for cooling would introduce additional savings.

A summary of the scenarios used to analyse the effects of variable heating and cooling demand – either due to geographical or building-related aspects – is reported in Table 4.

Table 4: *Price for heating and cooling in the investigated scenarios and GHGs' emissions.*

Scenario	Settlement typology	Location	Heating price[17] [€/MWh]	Cooling price [€/MWh]	Total CO_2eq [kton/year]	CO_2eq from electricity [%]
1FL	SFH/EX	London	88	-	5.4	31.7%
2FL	SFH/EX	Stuttgart	91	-	4.7	32.0%
3FL	SFH/EX	Rome	107	-	2.8	32.8%
4FL	s-MFH/EX	London	71	-	43.3	33.3%
5FL	s-MFH/EX	Stuttgart	72	-	41.8	33.4%
6FL	s-MFH/EX	Rome	81	-	25.2	33.6%
7FL	(SFH+s-MFH)/EX	London	74	-	24.4	33.0%
8FL	(SFH+s-MFH)/EX	Stuttgart	75	-	23.3	33.2%
9FL	(SFH+s-MFH)/EX	Rome	84	-	14.0	33.5%
4DH	s-MFH/EX	London	44	-	39.1	0.2%
10FL	s-MFH/45	Rome	75	77	20.9	38.9%
11FL	s-MFH/45	Rome	71	77	21.6	42.6%
12FL	s-MFH/45	Rome	66	74	23.6	48.3%
10DH	s-MFH/45	Rome	53	70	20.6	2.9%
11DH	s-MFH/45	Rome	53	85	21.2	5.7%
12DH	s-MFH/45	Rome	53	85	22.4	10.6%

As expected, the scenarios characterized by lower heat demands due to low density population (cases 1-3) had a smaller system and hence a lower equivalent annual cost (compare Figure 17 with Figure 18 and Figure 19). However, the specific cost of heating was higher in these cases (see Table 4). In fact, if it is true that some costs are proportional to the consumption (such as that of the gas used in the central boiler and that of the electricity used by the heat pumps), it is also true that investment costs of the system components are affected by the peak capacity of the system and not by the consumption. Additionally, in many cases economies of scale entail lower specific costs for larger

[17] The heating and cooling price in case of conventional DH and individual cooling is straightforwardly defined as the ratio between the annual cost of the two independent systems and the corresponding yearly energy demands. In the case of a FLEXYNETS system, the heating price was calculated as the ratio between the annual cost which is related to covering the heating demand and the yearly heating demand. The annual cost related to covering the heating demand was arbitrarily defined as the sum of the entire costs of the central heaters and waste heat, and a fraction of the costs for distribution network, pumping and heat pumps. This fraction was taken as the ratio between the yearly heat drawn from the FLEXYNETS network by the heat pumps in heating mode and the absolute value of the heat exchanged between heat pumps (both in heating and cooling mode) and network throughout the year. On the other hand, the cooling price in case of FLEXYNETS was defined as complementary to the definition of heating price.

installations. It is for example the case of the pipes of the distribution network and of the reversible heat pumps.

Looking at the scenarios where FLEXYNETS and conventional DH (+individual cooling, if needed) were compared, the following consideration can be drawn.

First, the FLEXYNETS systems presented an investment cost for the distribution network of the same order of magnitude as that of conventional DH. When considering the same boundary conditions, the network length for the two systems was the same. On the other hand, the lower temperature difference between supply and return pipe in the FLEXYNETS system required higher flow rates and hence larger metal pipe diameters compared to conventional DH. On the other hand, in the FLEXYNETS systems a lower thickness of insulation was assumed, thanks to the lower temperature difference between the circulated water and the soil. The combination of these two aspects caused the external diameter of the pipes to be roughly the same in both systems. Because the installation costs were assumed function of the external diameter of the pipes, these resulted to be similar, when comparing FLEXYNETS and conventional DH. The higher flow rates in the FLEXYNETS systems entailed a higher pumping cost (approximately 3 times higher), but this represented a very small fraction of the total annual cost, as seen in the cost composition diagrams.

Secondly, the FLEXYNETS systems presented a lower fuel consumption and hence a lower operation cost of the central boiler compared to conventional DH (ranging from -25 % to -40 % in the investigated scenarios 4, 10, 11 and 12). The lower heat load required by the distribution network in the FLEXYNETS systems was due to:

1. additional energy input provided by the heat pumps;
2. additional energy provided by the condenser of the heat pumps in cooling mode, when a cooling demand was present (as in the cases 10-12);
3. lower thermal losses, because of the lower temperature difference between network pipes and surrounding soil, which outweighed the lower pipe insulation.

For the same reasons, also the investment cost of the central boilers was lower, but it should be noted that this represented a very small fraction of the total annual cost. In fact, in the FLEXYNETS concept, the lower costs related to the central boilers were outweighed by the costs connected to the heat pumps. These were responsible of a significant fraction (approximately 50-60 %) of the overall annual cost, and they were equally shared between capital cost of investment and cost of electricity. Of the consumed electricity, the wider majority was used for heating purposes, given the larger heating demand compared to the cooling demand, also in a location like Rome. Concerning the cost of HPs, it should be noted that here no economies of scale were assumed. The used cost data were retrieved from the Danish Energy Agency (2016b); in Appendix C it is however discussed how independent estimates suggest that a cost reduction of at least 25 % should be easily achieved. Finally, concerning electricity consumption costs, it was already commented that here relatively low COP (about 4) values were assumed. Moreover, a parametric analysis on electricity prices will be reported later.

The comparison between a FLEXYNETS system and conventional DH + individual cooling in Rome (Figure 20) showed that the first was always more expensive. However, the cost difference decreased for increasing cooling demands (from +38 % in case 10 down to +9 % in case 12). In fact, in case of conventional DH, a higher cooling demand entailed the installation of individual split units, higher electricity consumption at a higher price (private consumer price vs. industrial consumer price) and lower efficiency of the cooling machines compared to the FLEXYNETS cooling. So, the fraction of the annual cost related to the cooling demand increased from 13 % to 42 %, when increasing the cooling demand from 25 % to 100 % of the nominal value.

On the other hand, the comparative scenario case 4 (London, s-MFH/EX) presented the highest competitive advantage for conventional DH compared to the FLEXYNETS concept, with an equivalent annual cost almost 40 % lower.

Based on what explained above, the cost difference between FLEXYNETS and conventional DH (+individual cooling) can be expected to be significantly higher for Northern and Central Europe than for Southern Europe. In fact, in colder climates the lower cooling demand and the stronger mismatch between heating and cooling demand profiles do not favour the FLEXYNETS concept, where a key role is expected to be played by the exploitation of simultaneous heating and cooling loads to compensate each other. Conversely, in warmer climates the wider overlapping between heating and cooling demand may make FLEXYNETS more competitive with respect to conventional DH, although still more expensive under the considered conditions, as seen in the cases 10-12. For this reason, no other scenarios applying FLEXYNETS in northern and central Europe were investigated[18], besides those already presented in Table 3.

The main reason why the FLEXYNETS system is more expensive than conventional DH + individual cooling even in the presence of a large cooling demand is the mismatch between cooling and heating profiles. The cooling demand (here assumed to be residential space cooling demand only) occurs only in summer and hence it is out of phase compared to most of the heating demand (space heating demand in winter time). The presence of a cooling demand in summer allows the FLEXYNETS system to use the condensing heat from the heat pumps in cooling mode to cover the low heat demand in this season. So, the operation of the central boiler is avoided. However, as the heat demand in summer is limited to DHW, only a small reduction in fuel consumption is achieved. Table 5 shows that although the condensing heat injected in the FLEXYNETS network increased from 10 GWh to 42 GWh from case 10FL to 12FL, the reduction in energy output from the central boiler was only 2.2 GWh and most of the condensing heat was dissipated by the central chiller and/or cooling tower. How this can be modified in the presence of seasonal storage is discussed in a later section.

Table 5: Summary of the main results from the scenarios 10-12FL (Location: Rome; Settlement typology: s-MFH/45).

	10FL	11FL	12FL
Heating demand [GWh/year]	75.9	75.9	75.9
Cooling demand [GWh/year]	8.6	17.2	34.4
Heat drawn by HPs’ evaporator [GWh/year]	56.9	56.9	56.9
Condensing heat from HPs’ condenser [GWh/year]	10.5	20.9	41.9
Boiler production [GWh/year]	50.9	49.5	48.7

[18] Within Deliverable D6.5, where FLEXYNETS early adopter cases are reported, one case where the FLEXYNETS application is estimated to be convenient even in a Northern Europe case is discussed.

Regarding the environmental impact, Table 4 shows the yearly CO_2 equivalent emissions in the different scenarios. As expected, the main contribution to the CO_2eq emissions in all scenarios came from the operation of the gas boiler. However, its share was much higher in case of conventional DH, where all the heat demand was covered by the gas boiler operation, and the use of electricity was limited to running the network pump and the cooling split units. On the other hand, in case of FLEXYNETS, where the central boiler covered only part of the heat demand, the share of CO_2eq emissions from natural gas was lower, while the share from electricity increased.

Based on the emission factors assumed for natural gas and electricity (Table 2), the total emissions did not differ considerably between a FLEXYNETS system and a conventional DH system covering the same energy demands. In fact, although the CO_2 emission factor for electricity was higher than that of natural gas, the FLEXYNETS system used a lower amount of primary energy, due to the re-cycling of the condensing heat from the cooling demand and the lower network losses. Only in scenario 4, FLEXYNETS was characterized by higher emissions, because this case did not have a cooling demand.

More significant results about CO_2 emissions are reported below, where the inclusion of waste heat is discussed.

6.2 Waste heat

Another advantage of the FLEXYNETS concept compared to conventional DH is the possibility of directly using low-temperature waste heat, so avoiding or reducing the operation of the central boiler. In this section the effect of the availability of low temperature waste heat on the economic feasibility of the FLEXYNETS concept is analysed.

For this analysis, the same boundary conditions as those in the cases 10FL, 11FL and 12FL (see Section 6.1) were used, i.e. constant heating demand and a cooling demand corresponding to 25 %, 50 % and 100 % of the nominal demand. The only difference between the original scenarios and the new ones (cases 13-18) was the availability of waste heat, whose availability profile was constant throughout the year and throughout the day. Two yearly amounts of waste heat availability were assumed, 27 GWh and 59 GWh, which were chosen so that the waste heat utilized by the network on a yearly basis represented respectively 30 % and 60 % of the network heat input (i.e. waste heat input + gas boiler input). The price of waste heat was assumed to be 10 €/MWh and its temperature 45 °C.

The boundary conditions for the new scenarios are summarized in Table 6, while the yearly profiles of heating and cooling demands as well as those of waste heat availability are shown in Figure 21.

Table 6: Assumptions made in the different waste heat scenarios (Location: Rome; settlement typology: s-MFH/45). The assumptions from the original cases 10-12FL are also listed for comparison.

	10FL	11FL	12FL	13FL	14FL	15FL	16FL	17FL	18FL
Heating demand [GWh/year]	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9
Cooling demand [GWh/year]	8.6	17.2	34.4	8.6	17.2	34.4	8.6	17.2	34.4
Waste heat available [GWh/year]	-	-	-	27.0	27.0	27.0	59.0	59.0	59.0

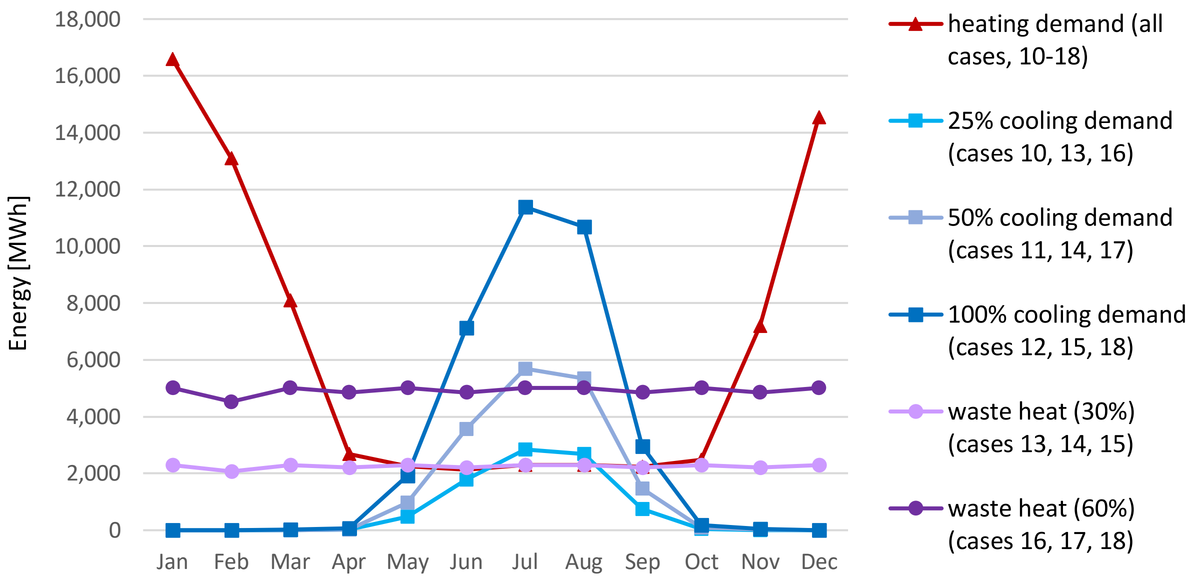

Figure 21: Profiles of heating and cooling demands as well as waste heat availability in the scenarios 12-18.

Table 7 presents a summary of the main results from the investigated scenarios, while Figure 22 shows the composition of their equivalent annual cost.

Table 7: Summary of the main results from the different waste heat scenarios. The results from the original cases 10-12FL are also listed for comparison.

	10FL	11FL	12FL	13FL	14FL	15FL	16FL	17FL	18FL
Waste heat used [GWh/y]	-	-	-	17.2	15.8	14.9	30.4	29.1	28.2
Ratio between used and available waste heat [%]	-	-	-	64%	59%	55%	52%	49%	48%
Boiler production [GWh/y]	50.9	49.5	48.7	33.7	33.7	33.8	20.5	20.5	20.6
Ratio between boiler production and network heat demand [%]	90%	87%	86%	59%	59%	59%	36%	36%	36%
Heating price [€/MWh]	75	71	66	70	66	62	66	62	58
Cooling price [€/MWh]	77	77	74	77	77	74	77	77	74
Total CO_2eq [kton/year]	20.9	21.6	23.6	16.6	17.6	19.8	13.2	14.3	16.5
CO_2eq from electricity [%]	39%	43%	48%	49%	52%	57%	61%	64%	69%

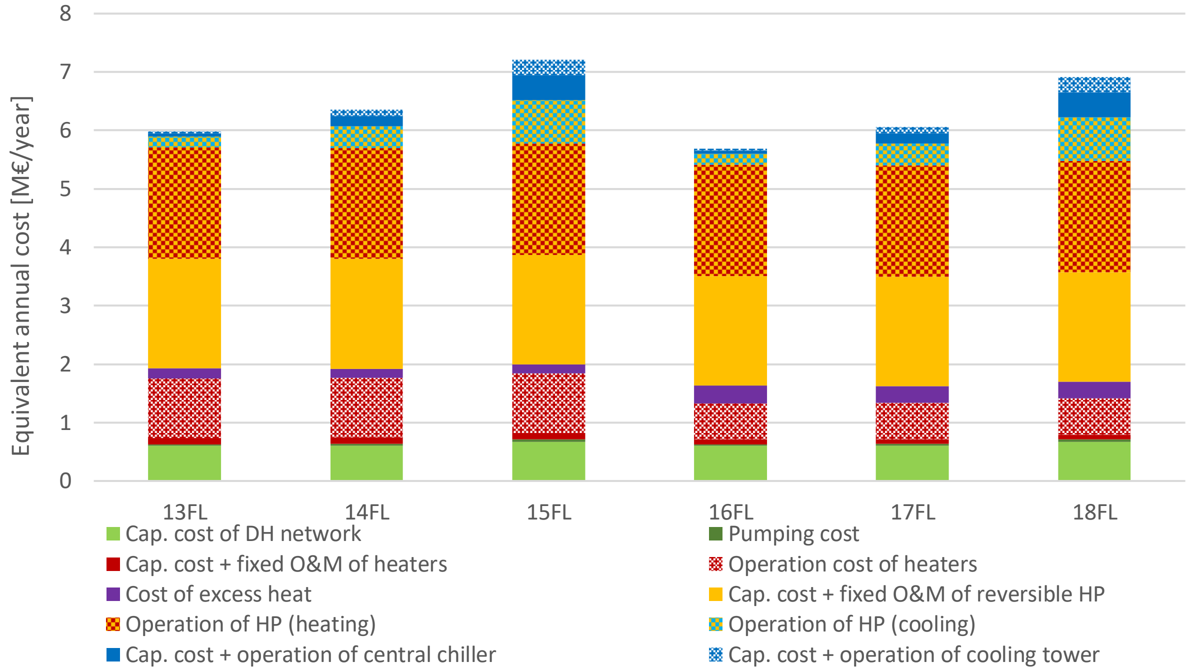

Figure 22: Composition of equivalent annual cost for the FLEXYNETS systems in presence of different amounts of waste heat.

As seen in Table 7, the higher the availability of waste heat (cases 16FL-18FL), the lower the energy required from the gas boiler (and hence the CO_2eq emissions). However, a higher availability of waste heat caused a lower share of waste heat recovery (i.e. the ratio between the amount of waste heat actually used and that available). Because the profile of the waste heat availability was constant[19] throughout the year, a higher amount of waste heat also made longer the period in which the available waste heat was higher than the net heat demand of the network (see Figure 21).

Table 7 also shows how the increase in cooling demand (out of phase with respect to the heating demand) negatively affected the waste heat recovery. When increasing the cooling demand from 25 % to 100 % in the scenarios 13-15FL, the share of waste heat recovery decreased from 64 % to 55 %. Similarly, in the scenarios 16-18FL, this share decreased from 52 % to 48 %. In fact, the higher cooling demand reduced the net heat demand of the FLEXYNETS network in the summer period (see also Section 6.1) and amount of waste heat which could be recovered[20].

From an economic perspective, the availability of cheap waste heat decreased the equivalent annual cost of the FLEXYNETS systems compared to the scenarios without waste heat. The savings coming from the reduced gas boiler operation more than compensated for the purchase of waste heat. However, as the fuel cost in the scenarios 10-12FL (without waste heat) represented 20 %-25 % of the equivalent annual cost, even a strong reduction in the natural gas usage had a moderate impact on the overall cost of the system.

[19] Realistic profiles for waste heat from shopping malls were presented in Chapter 5. Though they exhibit some daily and seasonal variability, approximating them with a constant profile is enough for the purpose of this analysis.

[20] The business model implicitly assumed here for waste heat does not force the network to buy all the available energy. Waste heat is bought only when needed. The remaining amount of waste heat is rejected through the cooling units at the corresponding sources. Other business models could require to absorb all the available waste heat, hence dissipating the excess amount on a centralized chiller. In such a scheme, the network manager would be expected to be paid for a district cooling service by waste heat sources, rather than to pay for their heat.

An effect which was not considered in this analysis was the possible reduction of pipe diameters in the distribution network. In case of more than one supply point to the network, not all the flow must be pumped from the central plant. Depending on the relative positions of the waste heat source, central plant and loads, a more distributed heat supply is likely to result in smaller diameters compared to a centralized heat supply. This could be particularly relevant for a FLEXYNETS system, which generally requires higher flow rates to compensate for the lower temperature difference. To correctly evaluate the network configuration and its cost, detailed information on the supply and loads distribution is required, which is out of the scope of this analysis.

6.3 Price of energy

Compared to a conventional DH system, a FLEXYNETS system uses much more electricity, primarily to run the heat pumps installed at the consumers' premises and secondarily because of the higher pumping energy. It is hence straightforward that the FLEXYNETS concept is more economically feasible in the presence of cheap electricity.

Regardless of whether a certain area is supplied by conventional DH or by a FLEXYNETS system, if the central plant uses a fossil fuel boiler (e.g. a gas boiler), a higher price of the fossil fuel will increase the operation costs of the system. However, when compared to a conventional DH system, a FLEXYNETS system will be less affected by a higher price of the fuel, because of the lower share of energy input coming from the central boiler. In fact, a FLEXYNETS system uses as energy input also the electricity absorbed by the heat pumps in heating mode, the condensing heat from the heat pumps in cooling mode and larger amounts of waste heat at low temperature.

Given the relevant effect of the price of energy on the feasibility of both conventional DH and FLEXYNETS, a sensitivity analysis on the energy price was carried out using the same boundary conditions as in the scenarios 10DH and 16FL, i.e.

- location of Rome,
- s-MFH/45 as settlement typology,
- 25 % cooling demand,
- high share of low-temperature waste heat (exploitable only by a FLEXYNETS network).

In the sensitivity analysis, the prices of energy originally assumed (30 €/MWh for natural gas, 100 €/MWh for electricity for industrial consumers and FLEXYNETS heat pumps, 200 €/MWh for electricity for private consumers) were varied between -50 % and +50 %. This range included all the energy prices in different European countries in the 2nd half of 2017 (Eurostat, 2018a; Eurostat, 2018b). Regarding the electricity prices, the FLEXYNETS system was only affected by the electricity price for industrial consumers, because no electricity consumption was assumed at private consumer price. In case of conventional DH and individual cooling, it was mainly the electricity price for private consumers which played a role, as the electricity consumed by the individual split units (paid at the private consumers' price) was much larger than the electricity consumed for pumping (see Figure 20).

The effect of the variation of the energy prices on the equivalent annual cost for the case 10DH and 16FL is shown in Figure 23. These two scenarios refer to a realistic case for Southern Europe, with a moderate cooling penetration (only 25 %) and an availability of low-temperature waste heat which can be directly exploited in a FLEXYNETS system but not with conventional DH.

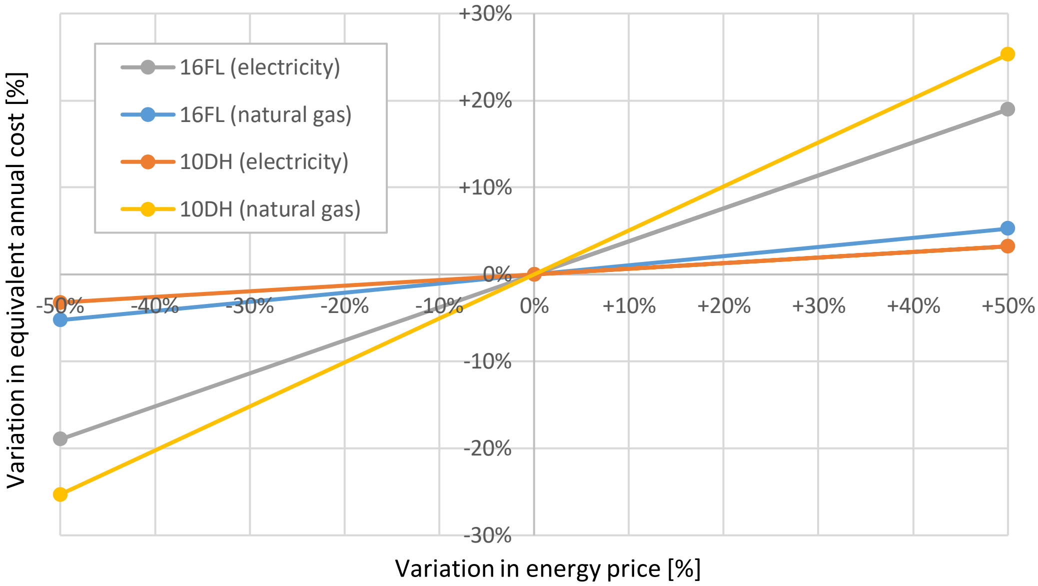

Figure 23: Variation of the equivalent annual cost for the case 10DH and 16FL as a function of the variation of the energy prices. The relative variation in the electricity price is the same for both residential and industrial customers.

Because the operation cost of central gas boiler represented an important share (more than 50 %, see Figure 20) of the equivalent annual cost of a conventional DH system, this was very sensitive to variations of fuel price. Figure 23 shows that an increase of gas price of 50 % would increase the equivalent annual cost by 25 %. At the same time, the annual cost of a FLEXYNETS system covering the same demands would increase by only 5 %.

On the other hand, a FLEXYNETS system was more affected by a variation in electricity price almost four times as much as the conventional DH system with individual cooling. However, if cases with the higher cooling demand had been considered, the operation cost of the individual split units would have been more relevant with respect to the equivalent annual cost and hence a variation in electricity price would have had a stronger impact. Moreover, applying different price variations to industrial and residential electricity prices (e.g., due to different taxations; see Appendix B for realistic cases) would also affect the two scenarios in different ways.

Because a FLEXYNETS system requires a higher investment costs compared to conventional DH, lower energy input and lower energy prices are required to make the system economically feasible. The trend of lower electricity prices seen in the last years in some European countries (see Appendix B) seems then favourable to the FLEXYNETS concept.

Finally, the cost composition of the original scenarios 16FL and 10DH was also investigated assuming that the energy sources (natural gas and electricity) were not taxed. Although this assumption may not seem realistic, these scenarios were treated to give an idea of the actual cost for the society. In fact, energy taxation is somehow an arbitrary decision of policy-makers and may be rearranged differently. Collected data for different European countries (see Eurostat, 2018a, Eurostat, 2018b, and Appendix B) show that the taxation on gas and electricity varies significantly, from a level of almost no taxation to a level where the applied tax is even higher than the market energy price. As a general trend, there are higher taxes on electricity than on gas in most European countries, hence considering the mere market price of energy may favour the FLEXYNETS concept.

In the following investigated scenarios, the following prices of energy (no taxation) were assumed, based on the 2017 average EU-28 values:

- 27 €/MWh for natural gas (-10 % with respect to the reference of 30 €/MWh, see Table 2),
- 75 €/MWh for electricity for industrial consumers (-25 % with respect to the reference of 100 €/MWh),
- 130 €/MWh for electricity for private consumers (-35 % with respect to the reference of 200 €/MWh).

Figure 24 shows the composition of the equivalent annual cost for the scenarios 16FL and 10DH with and without energy taxation. In the scenario 16FL, removing the energy taxes decreased the equivalent annual cost by approximately 11 %, in agreement with the sensitivity analysis shown in Figure 23. The diagram shows in fact that a reduction of the electricity price by 25 % entails a decrease in the overall cost by about 9-10 %, while a reduction of the natural gas price by 10 % entails a decrease in the overall cost by about 1-2 %. It should be noted that electricity prices around 75 €/MWh are not unrealistic, as these are already now present in countries like Norway, Sweden, Finland and The Netherlands for industrial consumers (taxes included).

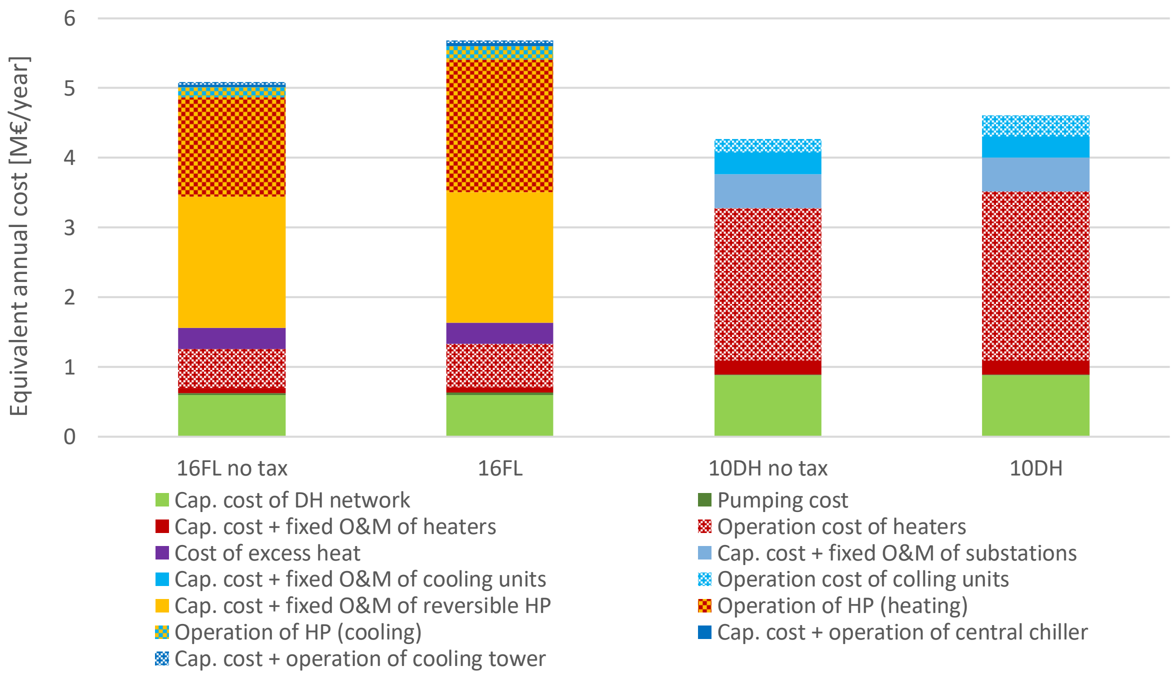

Figure 24: Composition of equivalent annual cost for the scenarios 16FL and 10DH with and without taxation on the energy sources.

On the other hand, in the scenario 10DH, the absence of energy taxes decreased the equivalent annual cost by approximately 7 %. In fact Figure 23 shows that a reduction of the electricity price by 35 % entails a decrease in the overall cost by about 2-3 %, while a reduction of the natural gas price by 10 % entails a decrease in the overall cost by about 5 %.

Based on these results, it can be concluded that removing energy taxation favours FLEXYNETS, tough not enough to make it less expensive than conventional DH for the considered scenarios.

A more extended summary on the variability of energy prices (independently of FLEXYNETS scenarios) is reported in the Appendices. There, the gas and electricity prices (industrial and residential, with and without taxes) for the 4 countries represented by the members of the FLEXYNETS consortium (Denmark, Germany, Italy, Spain) as well as for the EU-28 average are reported for the decade 2007-2016. These values confirm that the variability range considered here is reasonable. Moreover, one can observe that, for the EU average:

- Prices, while in general not changing dramatically, exhibit fluctuations up to about 30 %.
- Industrial gas and electricity prices without taxes experienced a slight reduction from 2007 to 2016 (-7 % and -4 % respectively); all other prices exhibited instead some increase.
- All taxes generally increased, especially for electricity.

Concerning the differences from country to country, it is interesting to note that industrial electricity prices are lower in Spain and Italy than in Denmark and Germany, but this is purely an effect of taxation. Indeed, while Spain has the lowest industrial electricity prices including taxes, it has the highest one excluding taxes (2016). In terms of the ratio between the electricity and gas industrial prices including taxes, the most favourable situation is again that of Spain, where industrial electricity costs 3.9 times as much as industrial gas (compared to 4.3 for Denmark, 4.9 for Germany, 5.5 for Italy).

6.4 Long-term storage

As mentioned above, the synchronicity between heating and cooling demand has a strong impact on the performance of a FLEXYNETS systems. Because the demands for space heating and space cooling are naturally out of phase, a long-term storage could play an important role in such a system, as this could store excess heat in summer time and make it available in the autumn/winter months. However, a storage operating within typical FLEXYNETS temperatures will have a low energy density and it will likely be expensive. Hence, its feasibility should be carefully investigated. A more detailed analysis on long-term storages in connection with the FLEXYNETS concept can be found in Deliverable D2.3.

In this Section the implementation of a long-term storage connected to a waste heat source was investigated and its impact on the economic feasibility of the system was assessed. The long-term storage was assumed to be a water-pit thermal energy storage (PTES). The specific cost per unit volume and the expected lifetime (25 years) of the PTES were retrieved from D2.3.

The investigated scenarios were built on the same boundary conditions as in the scenario 16FL, but the temperature of the waste heat was varied to assess its effect on the cost of the PTES. In fact, the lower the waste heat temperature, the lower the temperature difference within which the PTES operates. To store the same amount of heat, the PTES must be progressively larger and hence more expensive.

Three scenarios were investigated. In the scenarios 19FL, 20FL and 21FL, the temperature of the waste heat was assumed to be 45 °C, 35 °C and 25 °C respectively. The temperature at the bottom of the PTES was strictly related to the return temperature of the distribution network in the winter period, when the PTES was discharged. In winter the network supply temperature of 25 °C and the temperature difference of 10 K across the evaporators of the heat pumps in heating mode entailed that the return temperature was 15 °C. Hence the temperatures of 45 °C, 35 °C and 25 °C assumed for the waste heat source resulted in temperature differences of 30 K, 20 K and 10 K across the PTES.

In the three investigated scenarios the PTES was assumed to have a capacity of 22,000 MWh. This sizing allowed to avoid almost completely the operation of the central boiler and to recover almost the entire amount of available waste heat.
Table 8 presents a summary of the main results from the investigated scenarios, while Figure 25 shows the composition of their equivalent annual cost. The results from the scenario 16FL are also reported for comparison purposes.

Table 8: Summary of the main results from the scenarios with PTES. The results from the original cases 16FL are also listed for comparison.

	16FL	19FL	20FL	21FL
Waste heat used [GWh/y]	30.4	54.8	54.8	54.8
Waste heat temperature [°C]	-	45	35	25
ΔT across the PTES [K]	-	30	20	10
Ratio between used and available waste heat [%]	52 %	93 %	93 %	93 %
Boiler production [GWh/y]	20.5	0.4	0.4	0.4
Heating price [€/MWh]	66	70	72	78
Cooling price [€/MWh]	77	77	77	77
Total CO_2eq [kton/year]	13244	8227	8227	8227
CO_2eq from electricity [%]	61%	99%	99%	99%
PTES volume [m^3]	0	631,000	946,000	1,892,000

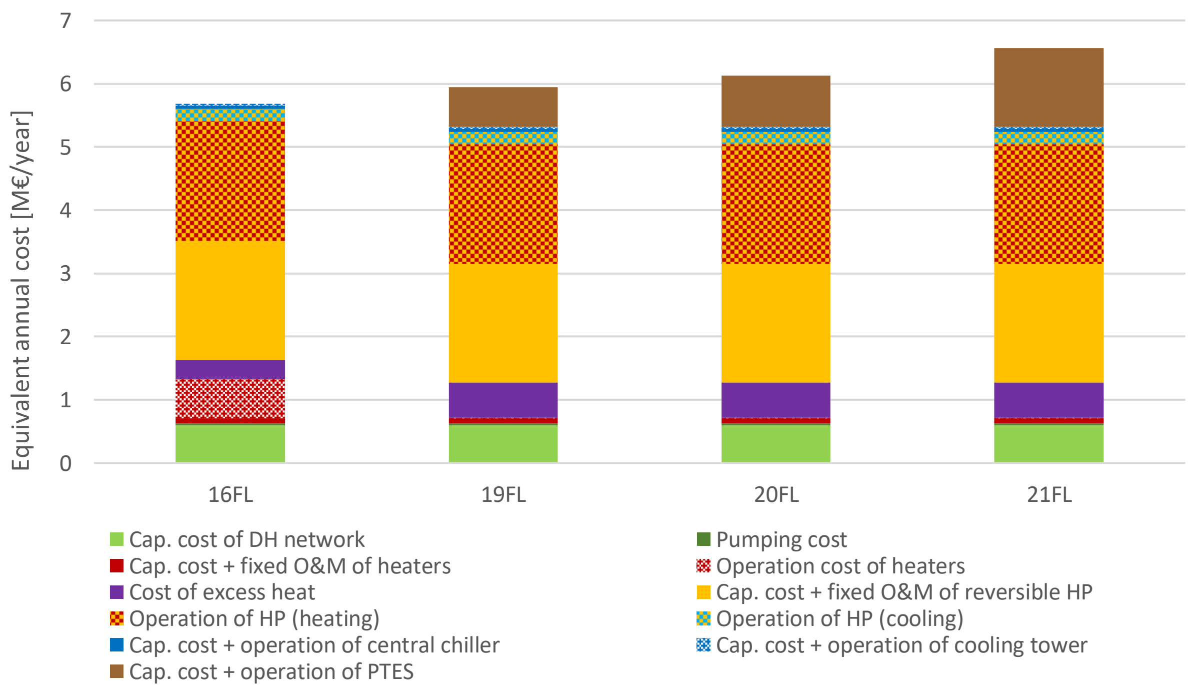

Figure 25: Composition of equivalent annual cost for the FLEXYNETS systems with long-term PTES connected to the waste heat source. Scenario 16FL is also shown as comparison.

Table 8 and Figure 25 show that all scenarios having a PTES were less economically attractive compared to the reference case 16FL, both in terms of equivalent annual cost and heating price. Based on how the cooling price was calculated, this was not affected by the presence of the PTES.
The increase in the cost was lowest in the scenario 19FL (+5 %), thanks to the availability of waste heat at higher temperature, which made the PTES smaller (631,000 m^3). However, its investment cost and the cost of purchasing additional waste heat were not compensated by the reduction in operation cost of the gas boiler. If it is true that the size of the central boiler could have been considerably decreased in the PTES scenarios, this would have decreased a cost component that had a marginal role in the overall cost composition (see Figure 25), so the above-mentioned considerations would still be valid.
For decreasing temperatures of waste heat, the implementation of the PTES became less economically competitive, because of the bigger volume of the PTES and hence higher investment cost. So, the scenario 20FL had an equivalent annual cost 8 % higher than the reference scenario 16FL, while the scenario 21FL, whose PTES operated with the same temperature difference of the network (10 K), had a cost 15 % higher compared to the scenario 16FL. It should be noted that the investment cost for the PTES increased less than proportionally with respect to the PTES volume. In fact, due to the economies of scale, the specific cost per unit volume decreased for larger PTES sizes (see D2.3).
Concerning economic aspects, another point should be considered. Indeed, it is not unlikely to expect that low-temperature waste heat can be obtained with lower prices than assumed here, possibly even for free. Actually, in a business model where the network guarantees to absorb all the available waste heat, thereby offering a reliable district cooling service to waste heat sources, there is no reason to assume a cost for waste heat. Such a business model could be more feasible just in the presence of seasonal storage, where excess heat could be absorbed and reused later, without the need of dissipating it with the relatively expensive operation of a centralized chiller. One can see in Figure 25 that cutting the waste heat costs would make scenario 19FL (seasonal storage with ΔT = 30 K) more convenient than 16FL (no seasonal storage). Similarly, cases with higher cooling penetration would correspond to the case of free waste heat.
Finally, if environmental aspects were considered (e.g. limitations on the amount of CO_2 which can be emitted and/or CO_2 taxation), the solutions offered by the PTES would be very relevant. In fact, as seen in Table 8, the assumed boundary conditions and the capacity of the PTES almost completely avoided the used of the central boiler, thus decreasing the emissions of CO_2eq by about 40 %. Consequently, apart from sheer economic considerations, the use of seasonal storage is very appealing from the environmental point of view.

6.5 Carbon emissions

The emissions of GHGs in the scenario 10DH were evaluated in case of different CO_2 emission factors for electricity. The original value of the emission factor (377 kg_{CO2}/MWh) was varied between 200 and 400 kg_{CO2}/MWh, a range which encompasses the values of emissions factors typical of most European countries. The effect of the CO_2 emission factor on the overall GHGs' emissions for case 16FL is shown in Table 9. As comparison, the emissions for the scenario 10DH are also shown, but for a constant emission factor of 377 kg_{CO2}/MWh. In fact, in case of conventional DH the impact of the electricity emission factor was very low, due to the low contribution of electricity (2.9 %) to the overall emissions.

Table 9: Emissions of GHGs in case 16FL as function of the CO_2 emission factor of electricity. As comparison, case 10DH is also shown.

	10 DH	16FL					
CO_2 emission factor for electricity [kg_{CO2}/MWh]	377	200	250	300	350	377	400
Total CO2eq [kton/year]	20.6	9.4	10.5	11.6	12.7	13.2	13.7
CO_2eq from electricity [%]	2.9%	45.7%	51.2%	55.8%	59.5%	61.3%	62.7%

Table 9 shows that under the assumed boundary conditions and in the presence of a high share of waste heat at low temperature, the FLEXYNETS system presents lower emissions compared to conventional DH (in the absence of high-temperature waste heat), regardless of the CO_2 emission factor assumed for electricity. Additionally, the FLEXYNETS concept offers a higher potential for further reduction. While the emission factor from natural gas is roughly constant (250 kg_{CO2}/MWh), that of electricity depends strongly on the energy mix that contributes to the electricity generation. In case of high penetration of RES, the CO_2 emission factor can also be lower than that of natural gas. For a CO_2 emission factor of 200 kg_{CO2}/MWh, the FLEXYNETS system presented overall GHGs' emissions 50 % lower than those of a conventional DH system.

6.6 Discussion

The results from the previous sections show that the FLEXYNETS concept is generally more expensive than a combination of a 3rd generation DH system and individual cooling, under the chosen boundary conditions. Nevertheless, based on results of the parametric analyses, it is possible to identify which factors favour the FLEXYNETS concept.

Section 6.1 showed that heating and cooling demands and profiles typical of Southern Europe are more favourable to the FLEXYNETS concept, because a larger amount of condensing heat in summer (i.e. heat from covering a cooling demand) can be recycled to cover the heat demand present in this season for DHW preparation. Additionally, the FLEXYNETS concept reduces the investment and operation costs to cover the cooling demand, which is not negligible in locations characterized by warm summers. In the FLEXYNETS concept, the reversible heat pumps providing cooling in summer are the same machines which provide heating in winter, so the investment cost is somehow reduced compared to a scenario with decoupled heating and cooling demands. Additionally, if reversible heat pumps are considered part of the supply side of the system (i.e., belonging to the network manager), the electricity price to be applied is equivalent to that for industrial consumer, considerably lower than that for private consumers, which is paid for the individual split units.

Section 6.2 showed that the availability of waste heat can strongly reduce the operation costs of a FLEXYNETS system. This was especially true when the waste heat is available in large amounts, cheap and at low temperature. High-temperature waste heat could obviously be exploited as well, but in this case also a conventional DH network could use it, so the difference in equivalent annual cost between the two systems would not be significantly affected.

Section 6.3 showed that the electricity price has a strong influence on the overall system cost. On the other hand, the price of the fossil fuel source has a lower impact, especially in the presence of large amounts of waste heat, which could replace this fossil fuel as energy source for the system. Hence the FLEXYNETS concept is more competitive with respect to conventional DH in scenarios where the price of electricity is low and that of fossil fuels is high.

Section 6.4 showed that, if large amounts of waste heat were available in summer, a long-term PTES storing this heat for later use might be considered. However, its economic feasibility is not guaranteed, due to the high investment cost and the low temperature difference the storage is likely to operate at. Even when not economically convenient, this solution entails a much lower environmental impact in terms of GHGs' emissions, because it significantly reduces the operation of the central boiler.

Section 6.5 showed that in the presence of a high share of low-temperature waste heat and in the absence of high-temperature waste heat, the GHGs' emissions from a FLEXYNETS system are much lower than those of a conventional DH. Additionally, as in Europe the CO_2 emission factor of electricity is generally decreasing, the FLEXYNETS concept seems to offer a higher potential in the decarbonisation of the space heating sector.

7 Conclusions and perspectives

This report explained general energy balances and economic figures for FLEXYNETS networks, including comparisons with traditional solutions. Some simple analytical relations were introduced, for example focusing on general bounds for the availability of waste heat in order to make environmentally convenient the considered approach. After reviewing technical aspects related to user substations and supply substations (related Deliverable D2.1), a set of parametric analyses was presented, in order to show the influence of different factors on the overall performances of these systems. Figures were reported in terms of annualized costs and emissions.

The main analysed aspects comprise:

- Dependence on heating and cooling profiles. This include geographical effects (as climate influences ambient temperatures), settlement typology effects (as building density influences load density), as well as building-related effects (as insulation and building size influence building loads). Different penetration scenarios for cooling were considered.
- Waste heat availability. Different amounts of low-temperature waste heat were considered, showing its impact on overall costs and environmental performances.
- Energy prices. In particular, the effects of different electricity prices were analysed, due to their high relevance in the presence of heat pumps.
- Seasonal storage. In the presence of a large mismatch between heating and cooling profiles (as can be expected as far as only residential loads are considered) this is a key ingredient to boost environmental sustainability, though economic costs are high.
- Carbon emissions. Emission factors for the electric grid are continuously evolving in time and strongly differ from country to country, significantly affecting the environmental performances of the system.

In general, it was found that from an economic point of view the FLEXYNETS approach is typically more expensive (order of 20 %, in several relevant scenarios) than traditional solutions. In a few scenarios, however, especially when all the strength points of this system appear together (low-temperature waste heat, non-negligible cooling demand, low electricity prices) economic convenience was observed. On the other hand, environmental benefits of including low-temperature waste heat were always evident.

While resulting from rather detailed investigations and reliable databases, the used economic figures (see Deliverable D6.11 – including the Excel tool User Manual – for details) entail a non-negligible uncertainty. An important example is provided by substation costs, a major item in all scenarios (due to the significant costs of heat pumps and corresponding auxiliary hydraulic equipment). Here, estimated costs were obtained putting together different heat pump price lists, detailed equipment costs, as well as information on typical geothermal installations. However, it was not possible to estimate economy of scale effects, which could play a major role in the deployment of thousands of similar components. Such an effect, difficult to estimate in a reliable way for a new technology, could play a significant role in lowering overall costs.

In conclusion, this work provides an assessment of the performances of FLEXYNETS networks in different scenarios, setting a useful basis for practical feasibility studies. In the task investigating Early Adopters cases, included in Deliverable D6.5, this approach is concretely applied to some real-world situations, in order to get preliminary estimates.

Appendix A – COP estimates

The overall COP of the system significantly depends on the average network temperature. To get some simplified estimate, a Carnot-like approximation for the COP of heat pumps was occasionally used. The ideal COP is given by the Carnot formula

$$\mathrm{COP}_C(T_e, T_c) = \frac{T_c}{\Delta T_{c-e}}, \tag{1}$$

where T_e and T_c are the evaporator and condenser temperatures respectively (to be expressed in Kelvin degrees) and ΔT_{c-e} is their difference. For a water-water HP, a rather poor approximation consists in using the average water temperatures at the evaporator and at the condenser of the HP within the Carnot formula. A much better approximation can be obtained roughly accounting for the main "real-world" effects, given by mechanical losses (e.g., at the pump) and by additional temperature differences at the evaporator and condenser heat exchangers. The following approximated formula is hence introduced

$$\mathrm{COP}(T_{eo}, T_{co}) = \eta_m \frac{T_{co}[\mathrm{K}] + \Delta T_{HEX}}{\Delta T_{co-eo} + 2\Delta T_{HEX}}, \tag{2}$$

where the evaporator and condenser temperatures in the ideal formula were replaced by $T_{eo} - \Delta T_{HEX}$ and $T_{co} + \Delta T_{HEX}$ respectively, having denoted by T_{co} and T_{eo} the outlet temperatures of the water at the condenser and at the evaporator side, respectively. In this way one calculates the cycle efficiency by using the temperatures of the internal working fluid (refrigerant fluid) and not the temperatures of the external water circuits.

Note that, in the real HP cycle, the internal fluid changes phase within heat exchangers, thereby remaining at constant temperature. On the contrary, the temperature of water varies along the heat exchanger, with a typical difference of 5 K between inlet and outlet. In order for heat exchange to occur, the transition temperature of the refrigerant fluid must be lower/higher than the minimum/maximum temperature of water in the heat exchanger. For example, at the evaporator (where heat is absorbed) the refrigerant temperature needs to be lower than the minimum water temperature in the heat exchanger. Minimum/maximum water temperatures at evaporator/condenser always occur at the heat exchanger outlet. This is why in the above formula only the outlet water temperature is used.

Typical pump efficiencies are of the order of 60-70 %, depending on the pump type, with low performances starting from 50 %. Typical temperature differences between the hot and the cold side of heat exchangers in heating and cooling applications are of the order of a few degrees, usually not beyond 5 K. Since here the considered temperature difference is not between the average hot and cold side temperatures, but involves the outlet temperature on one side – and considering that typical inlet-outlet temperature differences are of the order of 5 K – a difference of 2-3 K can be generally expected. Taking into account that in commercial heat pumps compactness requirements put a limit on the performance optimization of single components, a reasonably conservative estimate can assume η_m = 50 % and ΔT_{HEX} = 2.5 K (the evaporator and condenser heat exchangers are here assumed to be equal).

The above discussion is a significant simplification of the actual thermodynamic cycle of a heat pump[21]. Effects like possible overheating or subcooling of the refrigerant, as well as the dependency

[21] It is also worth mentioning that some heat pumps use slightly different cycles than the reversed Rankine cycle basically assumed here. In particular, this is the case for CO_2 heat pumps, where phase transition does not occur in the supercritical

of the heat exchange efficiency on flow rate, are completely neglected. Nevertheless, a comparison with typical heat pump data sheets yields a reasonable agreement. Using the Aermec WRL 081 heat pump model (one of the HPs used at EURAC laboratories) as a reference, one finds the results reported in the Table 10 (in the Aermec data sheet, values are provided as a function of the outlet temperatures and for an inlet-outlet temperature difference of 5 K).

Table 10. Comparison between the Aermec WRL 081 HP model, the approximated COP formula with η_m = 50 % and ΔT_{HEX} = 2.5 K (see also Table 13), and the Carnot COP.

T_{eo} [°C]	T_{co} [°C]	COP Aermec	COP approx.	COP Carnot
5	45	3.83	3.56	9.02
7	45	4.00	3.73	9.57
18	45	4.86	5.01	14.35

Table 11. Average COP values of the Aermec WRL series in heating mode.

		T_{co} [°C]				
		25	35	45	55	60
T_{eo} [°C]	5	7.17	5.10	3.86	3.03	2.71
	7	7.46	5.32	4.03	3.17	2.83
	10	7.84	5.63	4.28	3.37	3.02
	18	-	6.45	4.95	3.92	3.52

Table 12. Approximated COP values according to Eq. (2) with the best fit values for the Aermec WRL series η_m = 52.05 % and ΔT_{HEX} = 2.31 K (see text).

		T_{co} [°C]				
		25	35	45	55	60
T_{eo} [°C]	5	6.35	4.67	3.74	3.15	2.93
	7	6.91	4.95	3.91	3.27	3.03
	10	7.97	5.46	4.21	3.47	3.20
	18	13.46	7.48	5.28	4.13	3.75

Table 13. Approximated COP values according to Eq. (2) with the values η_m = 50 % and ΔT_{HEX} = 2.5 K (see text).

		T_{co} [°C]				
		25	35	45	55	60
T_{eo} [°C]	5	6.01	4.44	3.56	3.01	2.80
	7	6.54	4.71	3.73	3.12	2.89
	10	7.52	5.18	4.01	3.31	3.05
	18	12.53	7.06	5.01	3.94	3.57

For a specific heat pump model, one can also identify the best fit values for the above coefficients. However, since the approximated formula considered here is meant to be representative of a general heat pump, one should also take into account the variability of the COP with the heat pump

phase and temperature cannot be assumed to be constant at the condenser. Such HPs, however, are not considered in this project.

model. To this purpose, different sizes of the Aermec WRL heat pump series were considered, namely 9 sizes between about 8 and 50 kW of thermal power. It was found that COP values fluctuate by about $\pm$10 %, depending on size. Their average values (in heating mode) were then collected to get a general COP behaviour, as reported in Table 11. These values were then used as a reference to adjust the above coefficients. The best fit (least squares method) yields η_m = 52.05 % and ΔT_{HEX} = 2.31 K. The corresponding COP values are reported in Table 12, while the COP values for values for η_m = 50 % and ΔT_{HEX} = 2.5 K are reported in Table 13.

Some concluding remarks are in order. One can see that the maximum deviation of the best-fit approximated COP from the average values found for Aermec WRL series is about 15 %, occurring at T_{eo} = 18 °C and T_{co} = 35 °C. The average deviation is however only about 5 %. These numbers do not change significantly (though the maximum deviation occurs at different conditions, namely T_{eo} = 5 °C and T_{co} = 25 °C) when using the rule-of-thumb estimates η_m = 50 % and ΔT_{HEX} = 2.5 K, showing that the coefficient optimization is not particularly important.

On the other hand, it can be seen that the proposed approximation slightly overemphasizes non-linearity in the temperature dependence with respect to real heat pumps. In order to obtain more accurate performance maps of specific heat pump models, other approximations (e.g., linear models) can be more precise. Such detailed maps were used in WP2 to simulate residential substations. These models require however more fitting parameters (typically 5 coefficients instead of 2: a zero-order coefficient plus 4 first-order coefficients for all the inlet/outlet temperatures at evaporator and condenser), can be less reliable when extended beyond temperature ranges used for fitting, and do not offer such a simple connection with the underlying physical principles.

In conclusion, as the order of magnitude is well reproduced, the proposed formula with rule-of-thumb parameters is considered a reasonable choice for the present purpose (obtaining general COP estimates for system scenarios) and was implemented in the predesign Excel tool.

Appendix B – Energy prices, emission factors, and social costs of carbon

This Appendix reports an overview of energy prices (gas and electricity) and emission factors (electricity) across the European countries directly involved in FLEXYNETS, including also EU averages. A final section deals with the social costs of carbon. Indeed, though not explicitly taken into account in the scenarios described in Chapter 6, emission costs could represent an important variable for policy makers. Using the values reported in this Appendix, it is not difficult to estimate the impact of these costs on the overall costs of the reported scenarios.

B.1 – Energy prices

It is interesting to analyse the variability of prices for gas and electricity. To this purpose, Eurostat data for different countries (the four countries directly involved in the FLEXYNETS project – Denmark, Spain, Italy, Germany – plus the EU average) and years (the most recent available decade, namely the interval 2007-2016) were considered in the project. Some general plots and tables are reported below. Plots do not include the 2017 data (Eurostat, 2018a; Eurostat, 2018b) used in Chapter 6, but the source is the same.

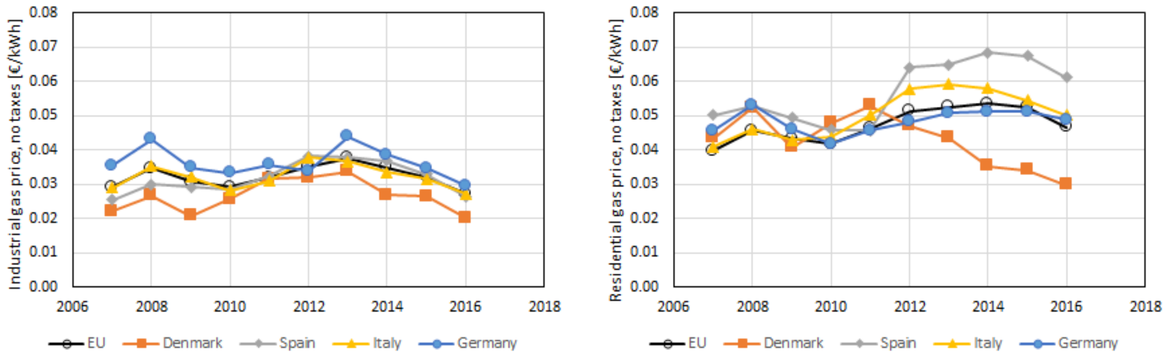

Figure 26. Gas prices (left: industrial; right; residential) without taxes..

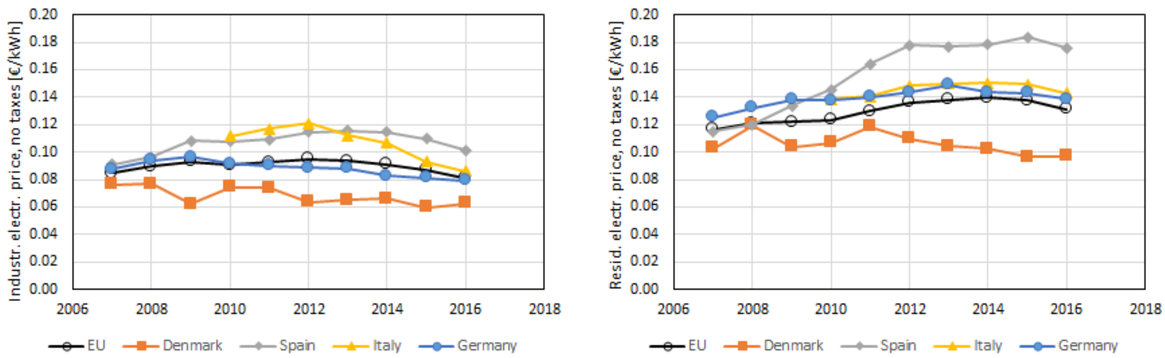

Figure 27. Electricity prices (left: industrial; right; residential) without taxes. For Italy, 2007-2009 data are not available.

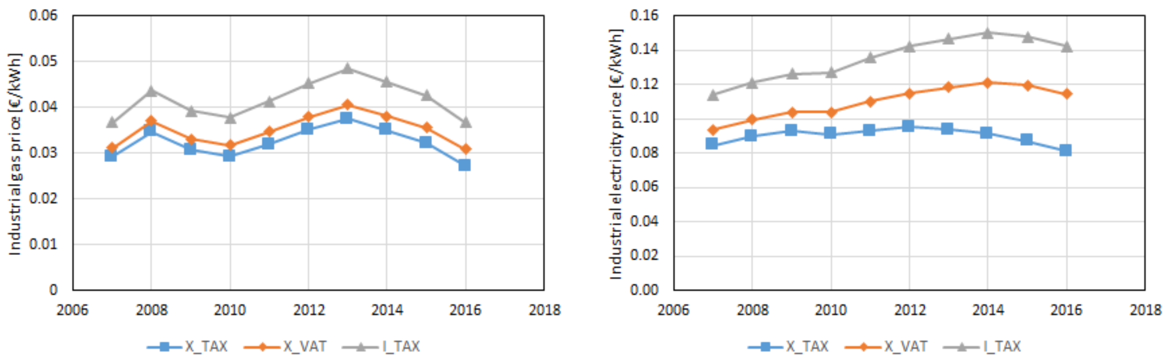

Figure 28. Effect of taxes (X_TAX = excluding all taxes; X_VAT = excluding VAT only; I_TAX = including taxes) on energy prices (EU average). Left panel: industrial gas. Right panel: industrial electricity.

Table 14. Industrial gas prices [€/kWh], excluding and including taxes.

Year	EU		Denmark		Spain		Italy		Germany	
	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax
2007	0.0292	0.0367	0.0220	0.0583	0.0255	0.0295	0.0290	0.0339	0.0355	0.0462
2008	0.0347	0.0437	0.0266	0.0647	0.0300	0.0348	0.0353	0.0409	0.0432	0.0561
2009	0.0308	0.0393	0.0207	0.0692	0.0292	0.0339	0.0321	0.0375	0.0349	0.0463
2010	0.0292	0.0378	0.0257	0.0672	0.0284	0.0333	0.0283	0.0330	0.0332	0.0454
2011	0.0319	0.0414	0.0315	0.0753	0.0323	0.0381	0.0310	0.0367	0.0356	0.0481
2012	0.0351	0.0453	0.0319	0.0773	0.0381	0.0453	0.0377	0.0458	0.0339	0.0451
2013	0.0375	0.0486	0.0338	0.0845	0.0377	0.0463	0.0366	0.0445	0.0438	0.0569
2014	0.0349	0.0456	0.0268	0.0788	0.0369	0.0452	0.0335	0.0408	0.0385	0.0506
2015	0.0322	0.0426	0.0264	0.0686	0.0328	0.0404	0.0315	0.0376	0.0346	0.0460
2016	0.0271	0.0367	0.0202	0.0613	0.0265	0.0328	0.0272	0.0325	0.0295	0.0400

Table 15. Residential gas prices [€/kWh], excluding and including taxes.

Year	EU		Denmark		Spain		Italy		Germany	
	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax
2007	0.0397	0.0511	0.0434	0.0850	0.0501	0.0581	0.0409	0.0636	0.0456	0.0613
2008	0.0456	0.0578	0.0524	0.0969	0.0530	0.0614	0.0461	0.0675	0.0530	0.0702
2009	0.0433	0.0554	0.0407	0.0827	0.0495	0.0573	0.0430	0.0646	0.0460	0.0619
2010	0.0417	0.0547	0.0478	0.0960	0.0459	0.0537	0.0437	0.0702	0.0418	0.0568
2011	0.0463	0.0608	0.0528	0.1030	0.0456	0.0538	0.0502	0.0785	0.0457	0.0614
2012	0.0514	0.0662	0.0471	0.0968	0.0641	0.0762	0.0578	0.0869	0.0481	0.0643
2013	0.0525	0.0680	0.0435	0.0985	0.0648	0.0812	0.0593	0.0890	0.0508	0.0675
2014	0.0535	0.0692	0.0353	0.0893	0.0684	0.0856	0.0579	0.0874	0.0512	0.0680
2015	0.0525	0.0687	0.0342	0.0783	0.0674	0.0844	0.0544	0.0836	0.0511	0.0679
2016	0.0467	0.0629	0.0298	0.0729	0.0611	0.0767	0.0502	0.0785	0.0488	0.0652

Table 16. Industrial electricity prices [€/kWh], excluding and including taxes.

Year	EU		Denmark		Spain		Italy		Germany	
	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax
2007	0.0847	0.1140	0.0765	0.2074	0.0912	0.1106	-	-	0.0876	0.1332
2008	0.0897	0.1210	0.0769	0.2179	0.0966	0.1173	-	0.1635	0.0940	0.1419
2009	0.0929	0.1263	0.0620	0.2104	0.1082	0.1319	-	0.1677	0.0967	0.1510
2010	0.0908	0.1268	0.0743	0.2282	0.1075	0.1322	0.1116	0.1630	0.0918	0.1535
2011	0.0928	0.1356	0.0740	0.2383	0.1091	0.1353	0.1170	0.1825	0.0900	0.1665
2012	0.0951	0.1422	0.0634	0.2406	0.1147	0.1440	0.1212	0.1997	0.0887	0.1715
2013	0.0935	0.1465	0.0652	0.2480	0.1154	0.1468	0.1121	0.1973	0.0883	0.1891
2014	0.0912	0.1501	0.0660	0.2584	0.1148	0.1460	0.1066	0.2017	0.0826	0.2032
2015	0.0870	0.1480	0.0597	0.2594	0.1097	0.1396	0.0931	0.1864	0.0811	0.1970
2016	0.0811	0.1422	0.0624	0.2658	0.1015	0.1291	0.0861	0.1789	0.0791	0.1966

Table 17. Residential electricity prices [€/kWh], excluding and including taxes.

Year	EU		Denmark		Spain		Italy		Germany	
	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax	Excl. tax	Incl. tax
2007	0.1165	0.1564	0.1027	0.2401	0.1152	0.1400	-	-	0.1253	0.2065
2008	0.1211	0.1624	0.1193	0.2710	0.1201	0.1462	-	0.2129	0.1320	0.2172
2009	0.1218	0.1640	0.1039	0.2627	0.1338	0.1631	-	0.2048	0.1380	0.2288
2010	0.1234	0.1705	0.1069	0.2689	0.1455	0.1790	0.1387	0.1943	0.1376	0.2407
2011	0.1300	0.1825	0.1187	0.2942	0.1641	0.2035	0.1405	0.2026	0.1401	0.2530
2012	0.1360	0.1926	0.1097	0.2985	0.1778	0.2233	0.1485	0.2215	0.1437	0.2636
2013	0.1380	0.2012	0.1042	0.2968	0.1770	0.2251	0.1500	0.2308	0.1491	0.2920
2014	0.1394	0.2058	0.1024	0.3039	0.1782	0.2266	0.1504	0.2392	0.1438	0.2978
2015	0.1377	0.2097	0.0966	0.3055	0.1840	0.2340	0.1493	0.2439	0.1429	0.2949
2016	0.1312	0.2053	0.0968	0.3086	0.1757	0.2235	0.1429	0.2377	0.1385	0.2973

B.2 – Emission factors

The renewability of European electric grids has been continuously increasing in recent years, typically in agreement with EU targets. It is hence interesting to analyse the evolution of emission factors. Equivalent CO_2 emissions (i.e., emissions including the contribution of all greenhouse gases, properly converted into equivalent CO_2 according to their global warming potential) are clearly related to primary energy factors, with the advantage of having a more straightforward interpretation.

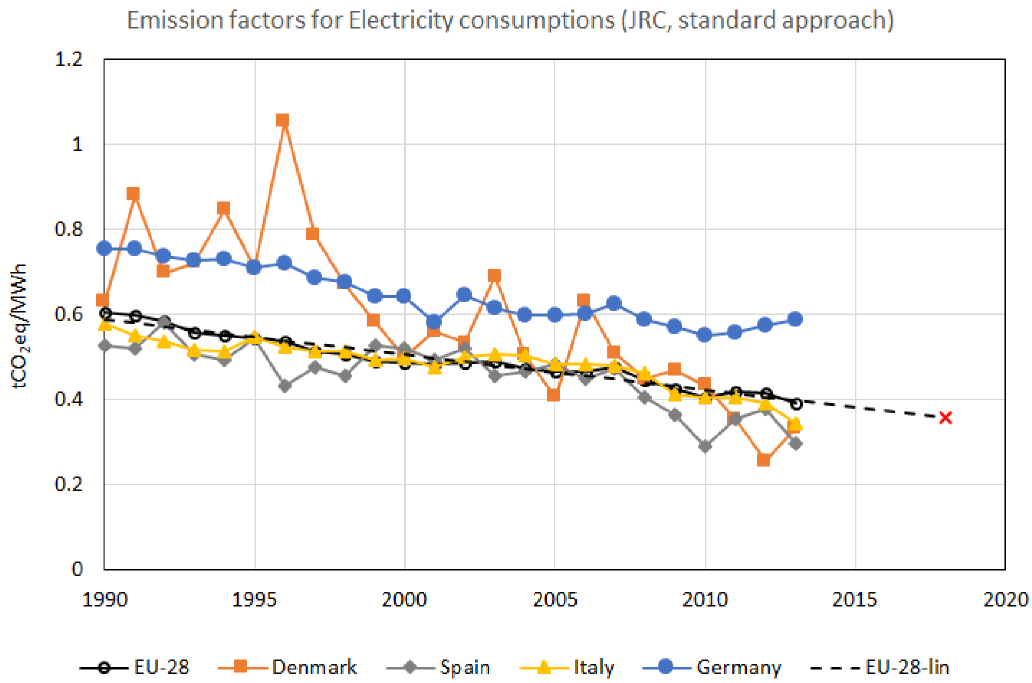

Figure 29. Electricity emission factors (in tons of equivalent CO_2 per MWh) for the EU-28 average and for the countries directly involved in the FLEXYNETS project. A linear fit of the EU-28 average is also shown. Data, taken from (Koffi, 2017), are available up to 2013. Extrapolating the linear trend, one could expect a value of 0.357 tCO_2/MWh for 2018 (see red cross in the plot).

As in FLEXYNETS the most relevant comparison in terms of primary energy of fossil fuel origin occurs between natural gas and electricity, it is useful to compare the two values. The emission factor of thermal energy produced from natural gas is here assumed to be[22] 0.250 tCO_2eq/MWh. As shown in the above figure, one can assume an average value of about 0.350 tCO_2eq/MWh for the current electric grid. The electric grid efficiency with respect to a natural gas source can then be estimated as η_{grid} = 0.250/0.350 = 71 %. This is a much higher value than often used in this type of estimates, where often non-updated values are used (efficiencies no higher than 45 % were typical in most countries until 2010). If the current trends will continue, even higher gas-relative efficiencies can be expected for the future (though, in general, one cannot expect linear extrapolations to be reliable on the long term), providing a more favourable framework for heat pump applications.

[22] According to the IPCC emission factors, stationary combustion in natural gas boilers gives rise to 0.202 tCO_2/MWh. Including additional (equivalent) emissions for gas transport, non-stationary operation, and plant efficiency, we increase this value by 25 %. Plant efficiencies can significantly vary, ranging from 80 % for old systems to nearly 100 % for most modern systems. Here, a simplified estimate is applied.

B.3 – Social costs of carbon

When improving an energy system, two objectives are typically pursued: a decrease in economic costs and in carbon dioxide emissions. Unfortunately, these two objectives are usually in conflict. In actual optimization problems, one can then adopt a multi-objective approach, possibly yielding a Pareto front of optimal solutions (i.e., solutions for which one cannot further improve one objective without worsening the other). Decision makers can then choose one of these optimal systems based on the relative importance they assign to the two objectives. A possible approach to reduce this multi-objective problem to a single-objective one is to assign a cost to CO_2 emissions. This can include some of the external costs expected for society as a consequence of fossil fuel pollution (e.g., global warming effects), allowing to define a "social cost of carbon" (SCC).

Identifying a reasonable value for social costs related to emission is clearly a very difficult task. Some numbers are being proposed by different researchers. A couple of relevant examples are given below:

- Costs assumed by US Environmental Protection Agency (EPA). For example, for a discount rate of 3 % (as typically applied in this Deliverable), a value of 42 US$/t$CO_2$ is assumed for 2020 (US Government, 2013).
- According to (Pindyck, 2016), the social cost of carbon can be estimated in the range 150-200 US$/t$CO_2$.

As it can be seen, this is a very wide range of variation. One can also observe the relation of these values with respect to fuel prices. For example, for natural gas an emission factor of 0.250 tCO_2/MWh is assumed in this Deliverable (see, e.g., Appendix C). On the other hand, the price of industrial natural gas without taxed is of the order of 30 €/MWh (see Appendix B). Hence, 1 ton of emissions corresponds to 4 MWh and hence to an energy cost of about 120 €. For 2018, an approximated exchange rate of 1.15 $/€ can be assumed, so that the US EPA value for the SCC can be converted to about 37 €/tCO_2. One can see that even applying this more conservative estimate of US EPA, one should charge costs of the order of 30 % to gas prices in order to account for environmental consequences. This is much higher than typical incentives related to white certificates for energy efficiency (typically of the order of 10 %).

Considering the large variability of the available estimates for SCC, instead of applying a specific value, one could compare scenarios assuming different policies for carbon taxes, e.g., 0, 50, 100, 150 €/tCO_2. In this way, it would be possible to measure all relevant objectives (economic and environmental) along a single axis, i.e., economic cost.

Appendix C – Economic costs

This appendix provides a summary of the main cost data used in the scenario estimates (Chapter 6), together with some extra information used for the solar CHP power station (D'Antoni et al., 2018). Further details can be directly found within the Pre-design Planning Tool, deliverable D6.11.

Annuity method. This a methodology to annualize investment costs (similar to levelized cost of energy). The annuity is defined as $a = r/[1-(1+r)^{-N}]$, where r is the interest rate and N is the lifetime in years. The interest rate used in this report is r = 3 % for all calculations. With this rate, for a lifetime N = 20 years one gets a = 6.7 %, while with N = 25 years one finds a = 5.7 %.

Economic data description. For each technology, economic data are reported as follows:

- Specific (unitary) investment cost. These are the costs as a function of the system size. Unless explicitly stated otherwise, these are turnkey costs.
- Lifetime in years. Different technologies can have different lifetimes.
- Operation and maintenance (O&M) costs. These are the annual costs for operating the equipment, excluding fuel or other energy costs.

Below is a summary for each technology.

Network costs

- A detailed analysis of pipe and civil works costs is reported in deliverable D3.1. The cost estimates done in the pre-design Excel tool are based on those values.

Decentralized equipment costs

- Heat pump costs
  - Specific investment cost. A first estimate was extracted from the Danish Energy Agency (2016b) data. Here, investment costs for ground source applications are available, with specific information for equipment. Data for 4 HP sizes are explicitly provided, which allow to extract specific costs in €/kWt. Since in FLEXYNETS higher COPs than for typical ground source applications are expected, this cost information was first converted into specific costs per unit of electric power, namely €/kWe (this was done on the basis of the COPs reported in the catalogue). It is indeed expected that costs are better parametrized on the compressor size, rather than on a COP dependent heating power. Then, fitting the available data with a power law, one gets the relationship 5466.6 × $P_{el}^{-0.299}$ expressed in €/kWe, where the electric power P_{el} is measured in kW. This yields about 27,500.00 € for a 10 kWe HP (i.e., 2750 €/kWe), corresponding to 50 kWt of thermal power P_{th} at COP = 5 (yielding 550 €/kWt). A second independent estimate was carried out by EURAC on the basis of the costs of the Energy Exchange laboratory[23]. Extrapolating these costs to a 50 kWt HP, one would expect an investment cost of about 21,000.00 €, i.e., about 25 % (i.e., 420

[23] The following cost splitting was estimated, according to the information provided by the contractor of the laboratory works: equipment (1 HP, 2 3-way valves, 1 puffer for DHW, 2 pumps, 1 heat exchanger for DHW, 1 heat meter, a forfeit amount of piping, all with sizes compatible with a heating power of 50 kW; see also Figure 5) for a total of about 15,000.00 € and other costs (design 10 %, transportation 3 %, installation 16 h, indirect costs 15 % and revenues 10 %) for a total of about 21,000.00 €. The price of the heat pump alone in this case was about 7,000.00 €, i.e., which is 1/3 (33 %) of the total turnkey cost.

€/kWt or 2100 €/kWe again assuming COP = 5). All these estimate are for single installations and do not include economies of scale.

- Assumed lifetime, 20 years (Danish Energy Agency, 2016b).
- O&M costs. Fitting the data (Danish Energy Agency, 2016b) as in the above case, one gets the behaviour $245.825 \times P_{el}^{-0.658}$ for the specific cost in €/(kWe·year), where electric power has to be expressed in kW.

- Traditional substation costs (Danish Energy Agency, 2016b)
    - Specific investment cost. Information relative to 3 sizes was available, yielding specific costs of 220 €/kW for a 10 kW substation, 70 €/kW for a 160 kW substation, and 40 €/kW for a 400 kW substation. Fitting the available data with a power-law function, one gets the behaviour $634.1 \times P_{th}^{-0.451}$ for the specific cost in €/kW, where the thermal power P_{th} has to be expressed in kW.
    - Assumed lifetime, 25 years.
    - O&M costs. For the 3 above sizes, O&M costs were also available. Fitting the data as in the above case, one gets the behaviour $33.67 \times P_{th}^{-0.767}$ for the specific cost in €/kW, where the thermal power P_{th} has to be expressed in kW.

Centralized equipment costs

- Centralized gas boiler (Danish Energy Agency, 2016a)
    - Specific investment cost, 60 €/kW.
    - Assumed lifetime, 25 years.
    - O&M costs. The above reference (Danish Energy Agency, 2016a) reports costs of about 1.1 €/MWh, which, assuming continuous operation throughout the year, would correspond to about 9 €/kW, i.e., 15 % of the investment.
- ORC (D'Antoni et al., 2018 and references therein)
    - Specific investment cost, 500 €/kW per unit thermal input power. Overall cost (including installation) more generally can be in the range 400-600 €/kW.
    - Lifetime, 20 years.
    - O&M costs, yearly rate of 3 % of investment costs. Electricity self-consumption can be in the range 7-15 % of the electricity output.
- Centralized chiller (EU H2020 Heat Roadmap Europe 4, 2016)
    - Specific investment cost, 120 €/kW per unit cooling power.
    - Lifetime, 20 years.
    - O&M costs, 4.6 €/kW per unit cooling power.

Seasonal storage (see Deliverable D2.3)

- PTES
    - A detailed cost analysis for seasonal storages has been reported in Deliverable D2.3. As a reference value for large storages (above 10^5 m^3), investment costs of 26 €/m^3

are assumed. According to available data, the general cost curve in €/m^3 proposed in D2.3 was 2266.7 $V^{-0.374}$, where V is the volume in cubic meters[24].

   - Lifetime, 25 years. This a tentative assumption (expected to be conservative) in the absence of long term historical data. See D2.3 for further details.
   - O&M costs, yearly rate of 0.7 % of the investment cost.

Solar collectors (D'Antoni et al., 2018 and references therein)

- FPC
   - Specific investment cost, 400 €/m^2. Overall cost (including balance of plant and installation) valid for field sizes of about 2000 m^2, roughly 1 MW of peak thermal power. A range of 300-600 €/m^2 can be generally expected, with lower costs for larger fields.
   - Lifetime, 20 years.
   - O&M costs. Assumed to be negligible. Electricity consumptions for pumping can be assumed to be about 1 % of thermal energy.
- PTC
   - Specific investment cost, 400 €/m^2. Overall cost (including foundations, balance of plant, and installation) valid for field sizes of about 2000 m^2, roughly 1 MW of peak thermal power. A range of 300-600 €/m^2 can be generally expected, with lower costs for larger fields.
   - Lifetime, 20 years.
   - O&M costs, yearly rate of 0.5 % of investment costs (e.g., for buying spare parts). Electricity consumptions for pumping can be assumed to be about 2 % of thermal energy.

[24] Costs of PTES storages can be divided in two categories: volume related costs with unitary value $c_V(V)$ (e.g., digging costs) and surface related costs with unitary value $c_S(S)$ (e.g., insulation). Assuming roughly that the surface S scales as $V^{2/3}$ (but this of course depends on the chosen geometry, since costs for the upper surface are different from costs for the bottom or lateral surfaces) one has that the overall cost can be represented as $C = c_V V + c_S S = c_V V + a_{SV} c_S V^{2/3}$, where $a_{SV} = S/V^{2/3}$ is some surface-volume conversion coefficient. Specific volumetric costs are then expected to scale as $C/V = \tilde{c}_V(V) = c_V(V) + a c_S(V^{2/3}) V^{-1/3}$. Finally, if volume related and surface related unitary costs are size independent, one has $\tilde{c}_V = c_V + a c_S V^{-1/3}$. This can at least be expected for large sizes. Some reference values reported in D2.3 are c_V = 16 €/m^3 and c_S = 138 €/m^2 for a 500,000 m^3 storage, with $\tilde{c}_V$ = 23.6 €/m^3 (against 67 €/m^3 for a 10,000 m^3 storage). This gives insight on the asymptotic behaviour which can be expected. From this data one can also estimate the surface-volume conversion coefficient to be about a_{SV} = 4.37 for that geometry. A formula of this type is in rough agreement with the power-law fit reported in the text only for large volumes (the fact that the exponent -0.374 is not far from -1/3 might be a coincidence, since c_V and c_S are not expected to be constant in the considered range).

Appendix D – Shopping malls

This appendix provides a focus on shopping mall waste heat profiles. Since there is not much literature on this point, it is considered useful to report more details on how to build parametric profiles (with parameters which can be easily scaled to adapt to the considered case).

The data of refrigeration units of an Italian shopping mall (partly based on simulation models developed in the CommONEnergy project, see reference EU FP7 CommONEnergy, 2017) were analysed in order to extract some typical behaviour:

- One has a rather constant relation between the average consumptions during opening ($\langle P_{op}\rangle$) and closing ($\langle P_{cl}\rangle$) hours. It was found $r_{op/cl} = \langle P_{op}\rangle / \langle P_{cl}\rangle =$ 1.76$\pm$0.02 for all months (the average is taken on all opening or closing hours of a single month).
- The consumptions during a given time period (opening or closing) are rather constant. In terms of relative standard deviation, one has $\delta_{op} = \sigma_{P_{op}} / \langle P_{op}\rangle = 11\ \% \pm 1\ \%$ and $\delta_{cl} = \sigma_{P_{cl}} / \langle P_{cl}\rangle = 8\ \% \pm 2\ \%$ for all months, where the symbol σ is used to denote the standard deviation and the symbol δ for its relative value with respect to the average.

Assuming that these are typical behaviours, one can think to use the following formula to reproduce the daily refrigeration profile of a shopping mall:

$$P(t) = \langle P_{cl}\rangle \{ [1 + \mathrm{rand}(-1,1)\delta_{cl}]\ (t \in \mathrm{closing}) + r_{op/cl}[1 + \mathrm{rand}(-1,1)\delta_{op}]\ (t \in \mathrm{opening}) \} .$$

This formula is based on 4 parameters, which can be extracted from the available data. Here $\mathrm{rand}(x, y)$ is a function generating random numbers within the interval (x, y), so that

$$\mathrm{rand}(-1,1) = 2\ \mathrm{rand}(0,1) - 1 .$$

The Boolean functions used to evaluate opening and closing profiles can be represented as

$$\begin{cases} (t \in \mathrm{closing}) = \vartheta(t - 0)\vartheta(t_{op} - t) + \vartheta(t - t_{cl})\vartheta(24 - t) , \\ (t \in \mathrm{opening}) = \vartheta(t - t_{op})\vartheta(t_{cl} - t) . \end{cases}$$

The ϑ functions are step (Heaviside) functions, t is expressed in daily hours, and t_{op} and t_{cl} are the opening and closing hours (e.g., 08:00 and 20:00), respectively.

The parameter $\langle P_{cl}\rangle$ refers to the average power during closing hours for the given day. Assuming the above formula, the average power for the same day is $\langle P\rangle = \langle P_{cl}\rangle (\langle t \in \mathrm{closing}\rangle + r_{op/cl}\langle t \in \mathrm{opening}\rangle)$. Since for typical schedules $\langle t \in \mathrm{closing}\rangle = \langle t \in \mathrm{opening}\rangle = 1/2$ (50 % time open, 50 % closed), one gets $\langle P\rangle = \langle P_{cl}\rangle (1 + r_{op/cl})/2$.

While the daily average power does not vary too much throughout the year, still some fluctuations occur. In the following, this aspect is also considered.

Figure 30 reports a simple representation of the main effects acting on the refrigeration system. Typically, the instantaneous performance of the refrigeration machine (COP or EER) is only affected by the refrigeration and the ambient temperature. Typically, cascade systems are used, where low-temperature (LT, of the order of -35 °C) and medium-temperature (MT, of the order of -10 °C) applications are grouped together. The overall EER (note that EER = COP-1) for the considered case oscillates between 1.1 and 2.6, mainly depending on the ambient (outdoor) temperature.

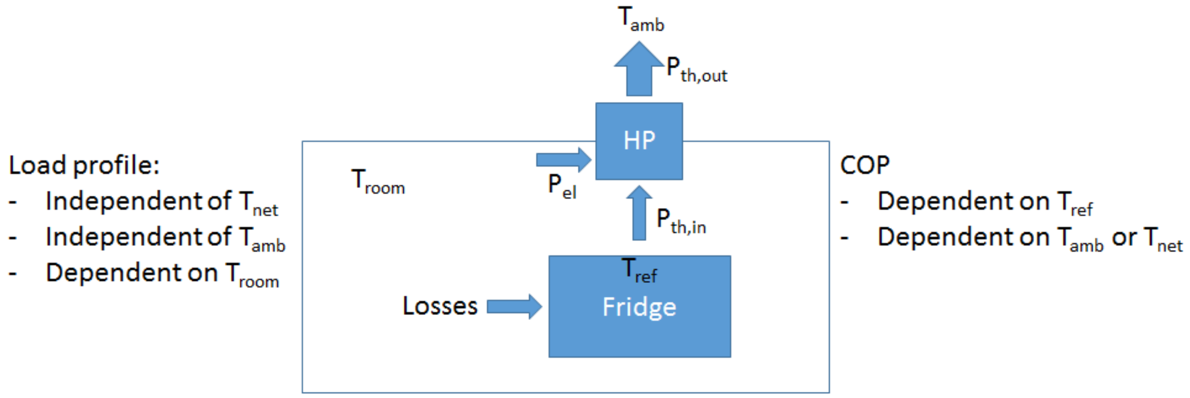

Figure 30. Simple representation of the main effects acting on the refrigeration system.

When connecting the system to a FLEXYNETS network, this performance should be significantly enhanced in summer and possibly slightly reduced in winter, reducing seasonal variations. Indeed, the condenser temperature of the HP would be fixed by the network temperature, which is expected to be in the range 15-25 °C (and hence lower than ambient temperature in summer, while higher in winter). From the simulation data (see Figure 31), a rather constant EER of about 1.8 could be expected throughout the year (i.e., a COP of 2.8).

The load profile depends on the specific use of the refrigeration system. In principle, one could expect that this profile does not depend on the ambient temperature, but only on the room temperature. The latter is set by the heating and cooling system with a set-point which depends on the season (20 °C for heating in winter, 24 °C for cooling in summer). The available simulation data, however, show that also the load profile has some dependence on the season (see Figure 31).

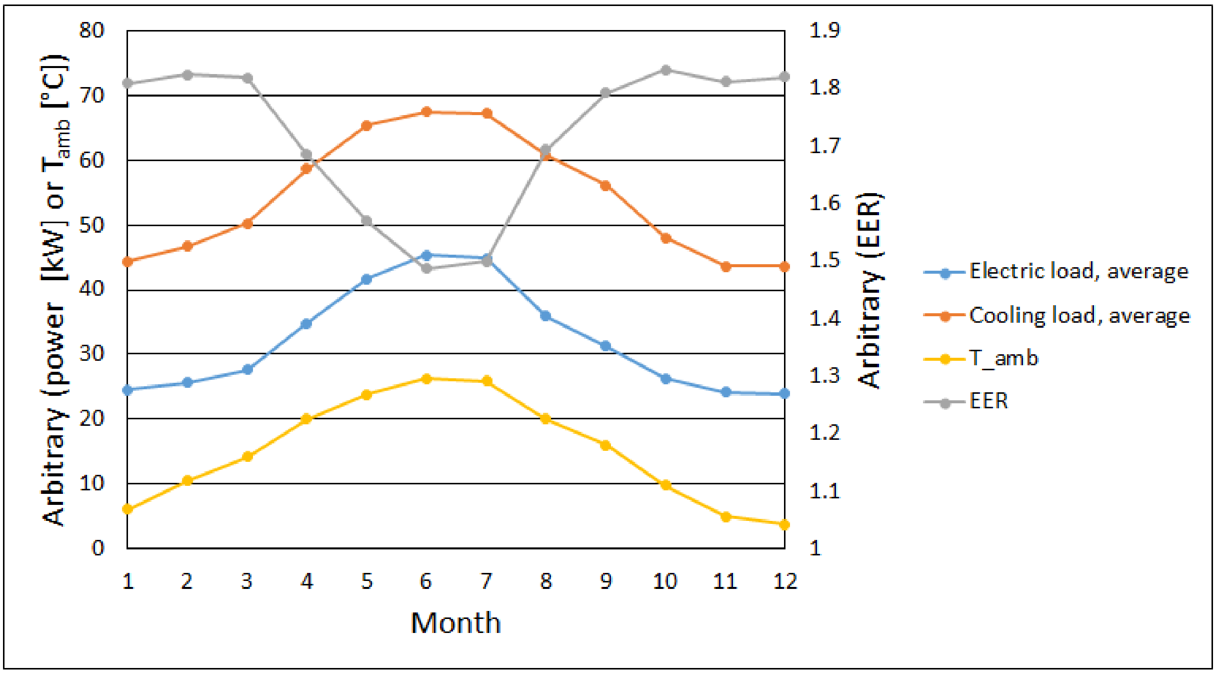

Figure 31. Monthly behaviour of the main system variables for the shopping mall taken as reference from the CommONEnergy project.

Summarizing, for a shopping mall connected to a FLEXYNETS system with stable network temperature, the operating conditions should be quite constant throughout the year (chillers would operate always between the same refrigeration temperature and the same network temperature), but still some seasonal effects would remain: for example, the different room temperature set point between summer and winter would give rise to different thermal losses and to different loads each time a fridge door is opened.

While from the point of view of a detailed shopping mall analysis all these assumptions might represent a poor approximation, from a network point of view they can be used to provide profiles with a realistic variability. The following formula for the average power $\langle P \rangle_n$ of the n-th day of the year is built on the available CommONEnergy data:

$$\langle P \rangle_n = \langle P \rangle_{year} \left[1 - r_P \cos\left(\frac{2\pi n}{365}\right)\right].$$

Here, $\langle P \rangle_{year}$ is the yearly average power (without distinction between opening and closing hours) and $r_P = \Delta P / \langle P \rangle_{year}$, where in turn $\Delta P = (P_{max} - P_{min})/2$ and P_{min} and P_{max} are simply calculated from the average of each month (i.e., they are respectively the minimum and maximum of the cooling load curve reported in Figure 31, whose behaviour is roughly reproduced by this formula).

The final proposed interpolation formula for the shopping mall waste heat profile is hence

$$P_{SMWH}(t) = \left(1 + \frac{1}{\text{EER}}\right) \frac{2\langle P \rangle_{year}\left[1 - r_P \cos\left(\frac{2\pi n}{365}\right)\right]}{\left(1 + r_{op/cl}\right)} \cdot \left\{\left[1 + \text{rand}(-1{,}1)\delta_{cl}\right] (t \in \text{closing}) + r_{op/cl}\left[1 + \text{rand}(-1{,}1)\delta_{op}\right] (t \in \text{opening})\right\},$$

where EER = 1.8, $r_{op/cl}$ = 1.76, δ_{cl} = 0.08, δ_{op} = 0.11, r_P = 0.22. The parameter $\langle P \rangle_{year}$ can be rescaled to match the desired size. If t is measured in hours, one has $n = \lfloor t/24 \rfloor$, where $\lfloor \dots \rfloor$ denotes the "floor" function.

Finally, as the random function varies abruptly, some post-smoothing can be applied. This also depends on the time step. For a 5 min step only little variations are generally expected. To implement fluctuations with the same width as above, but with a limited width on a short time scale, several methods can be applied. As an example, the following procedure can be applied:

- First, a simple bounded Markov chain can be built, i.e., a stochastic process where the distribution of the variable at a given time step depends (only) on the previous value of the variable. For example $x(t) = \max\{-1, \min[1, x(t - \Delta t) + w\ \text{rand}(-1{,}1)]\}$.
- Second, some smoothing (e.g., a moving average) can be applied to the overall resulting series (so that also the steps between closing and opening hours are smoothed out) in order to avoid large spikes.

Anyway, as the data shown in Figure 12 and Figure 13 of Section 6.2 actually show significant short time fluctuations, the importance of this smoothing does not seem to be crucial.

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