D2.3 - Large Storage Systems for DHC Networks

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

FLEXYNETS

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Executive summary

In this report, the potential role of large-scale thermal energy storages in the FLEXYNETS concept has been analyzed. The report focuses on four storage types; tank, pit, aquifer and borehole storage (TTES, PTES, ATES and BTES respectively). The storage time scales, temperatures, volume, storage medium and investment costs have been described and quantified in the context of FLEXYNETS. The required storage volume and investment costs are highly dependent on the temperature difference in the storage. As the FLEXYNETS concept works with very low temperature differences between forward and return temperatures (approx. 5-15 K difference), this would require any thermal energy storages that work at the FLEXYNETS network temperature to be larger and more expensive than storages of the same energy storage capacity working at conventional district heating temperatures. However, if the amount of surplus heat is significantly higher at low temperature, it may be more feasible to choose a connection to this low temperature heat source. Also in this case it may be feasible to include a storage.

The utilization of surplus heat is an important aspect of the FLEXYNETS concept. Transmission pipeline costs for the utilization of surplus heat have been analyzed in connection with the thermal storages. The results suggest that sourcing surplus heat at even several kilometres away from the FLEXYNETS network can be economically feasible, as long as the surplus heat source is sufficiently large compared to the network demand and as long as the assumptions of the model are applicable. In reality the actual feasible transmission distance depends on local conditions and boundary conditions and must be evaluated individually in each case.

Situations have been identified in which large-scale thermal energy storages could be most relevant in the FLEXYNETS concept. This is in case surplus heat is available at temperatures higher than the FLEXYNETS network temperature, and this heat is directly transferred, via a transmission pipeline, to a thermal energy storage. The storage can in that case take advantage of the larger temperature difference between the surplus heat temperature and the FLEXYNETS cold pipe temperature, which lowers the required storage volume and investment compared to operating only at FLEXYNETS temperatures.

This system has been modelled in the simulation software *TRNSYS*. The simulations have been carried out for all four thermal energy storage types and for three reference cities; Rome, London and Stuttgart. The simulations have been performed for different operating temperatures and for different amounts of surplus heat availability. The results of the simulations have been evaluated based on two indicators: the average thermal energy generation cost in the system (in €/MWh) and the annual CO_2 emissions arising from satisfying the heating and cooling demand in the system (in kton/year).

A storage can in general balance fluctuations in surplus heat supply and network heating and cooling demands, thereby facilitating more efficient usage of the incoming surplus heat and reducing the required auxiliary energy supply to the network (and any associated CO_2 emissions).

The results of the simulations show that especially ATES but also PTES and BTES can be very relevant as seasonal storage in the FLEXYNETS concept, in case surplus heat at temperatures above the FLEXYNETS operating temperature is available. Investing in such thermal energy storages can significantly lower the system's annual CO_2 emissions associated with heating and cooling (by up to 95% in investigated scenarios), and either lower the thermal energy price (in investigated scenarios up to 50%) in the system or at least keeping it at a similar level compared to a system without the storage. The storage types all have different benefits and drawbacks depending on the system they are a part of. The conclusion is therefore that although large-scale thermal energy storages are not always relevant for the FLEXYNETS concept, they can be very beneficial to the system in certain cases, in particular if surplus heat above the network temperature is available in large quantities, and are therefore worth considering when evaluating specific cases in more detail.

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1 Introduction

This report describes how large thermal storage systems (TES) can be used not only in general for district heating and cooling (DHC) networks, but also in the context of the lower temperature levels of a FLEXYNET. The aim is to provide answers to the question if and in what contexts large-scale thermal storages could be beneficial for the FLEXYNETS concept. The analysis includes both spatial requirements, energy performance (temperature dependency) and economics of such storages.

Four types of large thermal energy storages are considered in this report. These are tank storage (TTES), pit storage (PTES), aquifer storage (ATES) and borehole storage (BTES). In all cases the energy storage medium is assumed to be liquid water.

In chapter 2 of this report, some general principles of thermal energy storages are introduced and discussed in terms of the FLEXYNETS concept. These are principles related to storage time scale, categorization, temperature, volume, storage medium and economics of scale. In chapter 3, a more detailed description of the physical and economical parameters for each storage type is given and discussed in terms of storage temperature levels. In chapter 4, the utilization of surplus heat e.g. from industrial sources is discussed, with a focus on the transmission pipeline costs related to this (i.e. how long a transmission pipeline could be feasible to connect the heat source and the storage). In chapter 5, a model system with surplus heat and large-scale thermal energy storages is described and modelled using the *TRNSYS* simulation software. Data from chapter 3 and 4 are used as inputs for the model. The performance of the different thermal energy storage technologies in the modelled system is evaluated economically (in terms of the resulting energy price in the network) and technically (in terms of the CO_2 emissions reduction). In chapter 6, the main findings of the report are summarized.

2 General principles of thermal storages

2.1 Storage time scale, categorization, temperature and volume

2.1.1 Time scale for storing

The idea of thermal energy storage is to utilize energy being generated while the production conditions are as effective and favourable as possible. Examples include the production of solar thermal during the day, heating or cooling generation in heat pumps while electricity prices are low, and the production of electricity and heat in a CHP plant while electricity prices are high.

Energy storage helps decoupling the production from the demand, which is useful in systems where it is difficult to regulate the production profiles. This is the case in systems with high shares of fluctuating renewable energy such as solar thermal. This can also be true for systems with a constant inflow of surplus heat from industrial processes, which does not necessarily match the daily or seasonal variations in the heating and/or cooling demand. The storage thereby increases the flexibility to utilize sources of energy that cannot be regulated to fit the demand profile.

The basic principle of separating the production and demand in time can be either on a short-term basis or on a seasonal time scale. While small-scale storages for very short periods (e.g. only on hourly basis) may be useful on local level, the term "short-term storages" is used in this report for storages from daily variations up to weekly storage capacity. "Long-term storages" refer to storage capacities that can account for seasonal variations. The capacity of short-term and long-term storages in this regard, depends on the system properties (including production technologies and specific demand) to which the storage is connected.

2.1.2 State of the storage medium

Thermal energy storages can be divided into four physically different technologies according to the state of the storage medium:

Sensible storage: Use the heat capacity of the storage material. The storage material is most often water due to its favourable properties e.g. having a high specific heat per volume, a low cost and being a non-toxic medium.

Latent storages: Make use of the storage material's latent heat during a solid/liquid phase change at a constant temperature.

Chemical storages: Utilize the heat stored in a reversible chemical reaction.

Sorption storages: Use the heat of ad- or absorption of a pair of materials such as zeolite-water (adsorption) or water-lithium bromide (absorption).

This report focuses on sensible heat storages only, since the typical use of storages in DHC networks does not involve latent, chemical or sorption heat storages. Furthermore, the aim of the FLEXYNETS concept is to use existing and proven technology if possible, and latent, chemical and sorption heat storages are still being developed and have not been widely demonstrated or adopted for large-scale heat storage.

2.1.3 Temperature level and volume requirements

The temperature level in storages can range from cold storages used for cooling purposes to hot storages, where the temperature in the top of the storage corresponds to the supply temperature of the district heating network. The heat storage capacity depends on the temperature levels in the storage. The energy storage capacity for sensible heat storage is

$$Q = m \cdot c_p \cdot \Delta T \qquad \text{(Equation 1)}$$

where m is the mass of the storage medium, c_p is the specific heat capacity of the storage medium and ΔT is the difference between the maximum and minimum operating temperature of the storage. The larger the temperature difference, the higher the heat storage capacity is for a fixed mass of the storage medium. Using Equation 1, the volume V required for storing one unit of energy Q (i.e. the specific volume) can be written as

$$\frac{V}{Q} = \frac{V}{m \cdot c_p \cdot \Delta T} = \frac{1}{\rho \cdot c_p \cdot \Delta T} \qquad \text{(Equation 2)}$$

where ρ is the density of the storage medium ($\rho = m/V$). The absolute volume required for storing the energy content Q with a temperature difference of ΔT is thus

$$V = \frac{Q}{\rho \cdot c_p \cdot \Delta T} \qquad \text{(Equation 3)}$$

These results apply to a storage medium at ambient pressure, regardless of the storage technology, and excludes any additional volume required for containing the storage medium (i.e. storage walls and insulation).

2.2 Water as a storage medium

Existing Danish heat storages for district heating systems are usually with water as the storage medium. The reasons include that water is non-toxic, allows for temperature layering (stratification), can provide large effects when charging and discharging, has good heat transfer properties, has a high specific heat capacity and is relatively cheap. The specific heat capacity of water is approximately 4.18 kJ/(kg·K), which is higher than that of most other low-cost, abundant materials such as sand, iron and concrete. Some examples of specific heat capacities are given in Table 2.1.

Due to its advantages, water is the most widely used storage medium for storing heat at temperatures below 100 °C. If pressurized, water can also be used for storing heat at temperatures above 100 °C. In Figure 1, Equation 2 has been used to plot the dependence of the specific energy storage volume on ΔT for the case of water as the storage medium. Due to the inverse proportionality of the specific volume and the temperature difference between the storage inlet and outlet (ΔT), it is considerably more "bulky" to store heat in the form of water for small values of ΔT than for large values of ΔT.

Table 2.1 – The volumetric specific heat capacities of a few inexpensive, abundant materials (PlanEnergi, 2013).

Material	Capacity (kWh/m³/K)
Water	1.16
Steel	1.07
Concrete	0.58
Soil	0.8 - 0.9

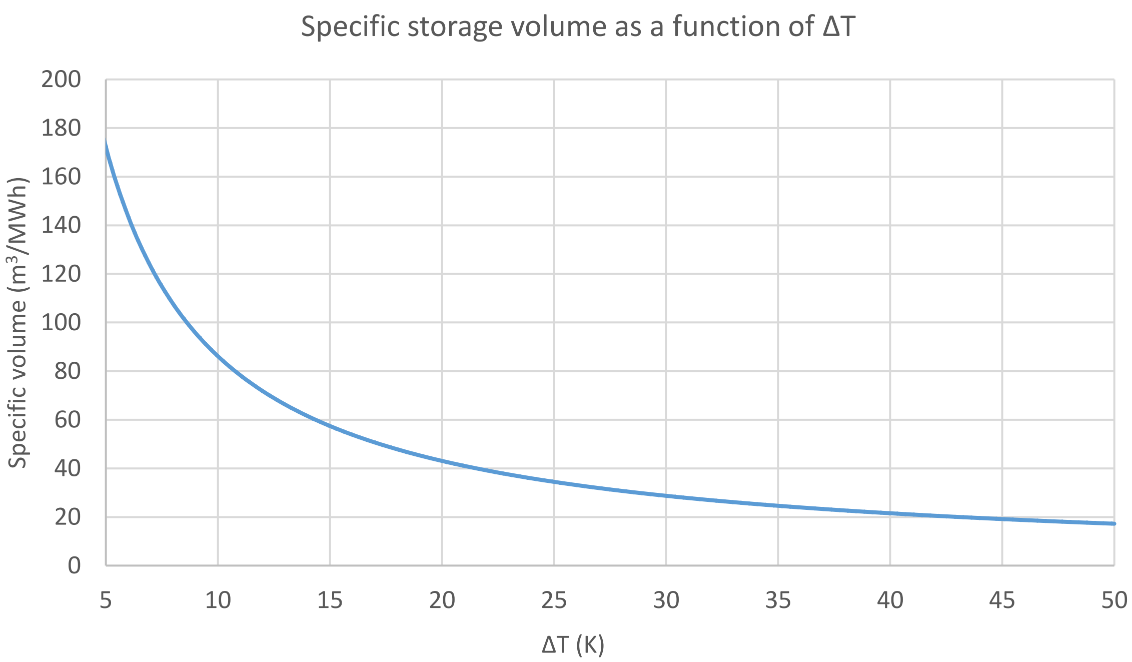


Figure 1 – The required volume for sensible storage of one MWh of heat as hot water shown as a function of the temperature difference between the maximum and the minimum storage temperatures.

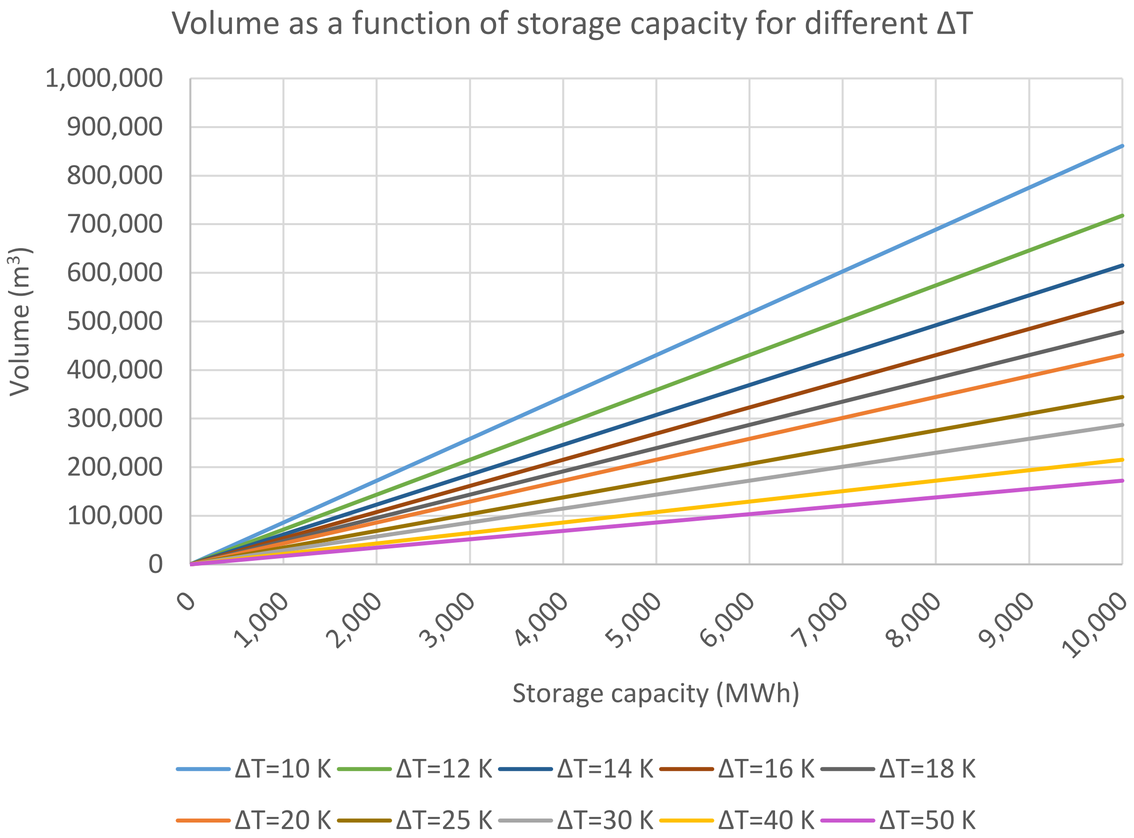


Figure 2 – The required storage volume as a function of the heat storage capacity when storing heat in the form of hot water, shown for a few different values of ΔT.

Consequently, very large volumes are required to store large amounts of heat with a small difference between the maximum and minimum storage temperature. In Figure 2, Equation 3 has been used for plotting the required storage volume as a function of the required storage capacity for different values of ΔT. As can be seen in figure, the difference in the required absolute volume can be very large when storing large amounts of heat in the form of water at different ΔT values. The benefit of an increased temperature difference becomes less pronounced at higher values (e.g. changing from 40 K to 50 K) compared to the lower examples (e.g. changing from 10 K to 20 K). In other words, at the low operating temperatures of FLEXYNETS, a slight increase in ΔT can have a big impact when it comes to storages.

2.3 Energy storage economics of scale

Similar to most other energy conversion and/or storage facilities, the specific investment costs of heat storages (defined as costs *C* per unit of volume) are dependent on its dimensions in the form of a power law:

$$\frac{C}{V} = a \cdot V^b \Longrightarrow C = a \cdot V^{b+1} \qquad \text{(Equation 4)}$$

For a given type of storage, the constants a and b can be found by fitting a power-law to a data set containing investment cost data for an array of differently sized storages.

By combining Equation 4 and the expression for the required storage volume from Equation 3, the following expression for the economics of scale as a function of the energy storage capacity and the temperature difference can be obtained:

$$C = a \cdot \left(\frac{Q}{\rho \cdot c_p \cdot \Delta T} \right)^{b+1} \qquad \text{(Equation 5)}$$

This method of evaluating the economics of scale is used later in this report for the investigated storage types.

3 Physical and economical properties of selected storage types

3.1 Investigated storage types

The following large-scale storages are investigated:

- Steel tanks (centralized “daily” water storages)
- Water pit storages (centralized “daily” to “seasonal” storages)
- Borehole storages (centralized “daily” to “seasonal” storages)
- Aquifer storages (centralized “daily” to “seasonal” storages)

These storage types are analyzed and described in terms of energy density, costs etc. depending on the temperature levels. A thing to consider in a given context is whether it is more feasible to store at

a) low temperatures (because the investment in insulation can be reduced and/or more surplus heat may be available at low temperatures)

or

b) high temperatures (because this will mean higher energy density and thereby a smaller storage volume for the same energy content).

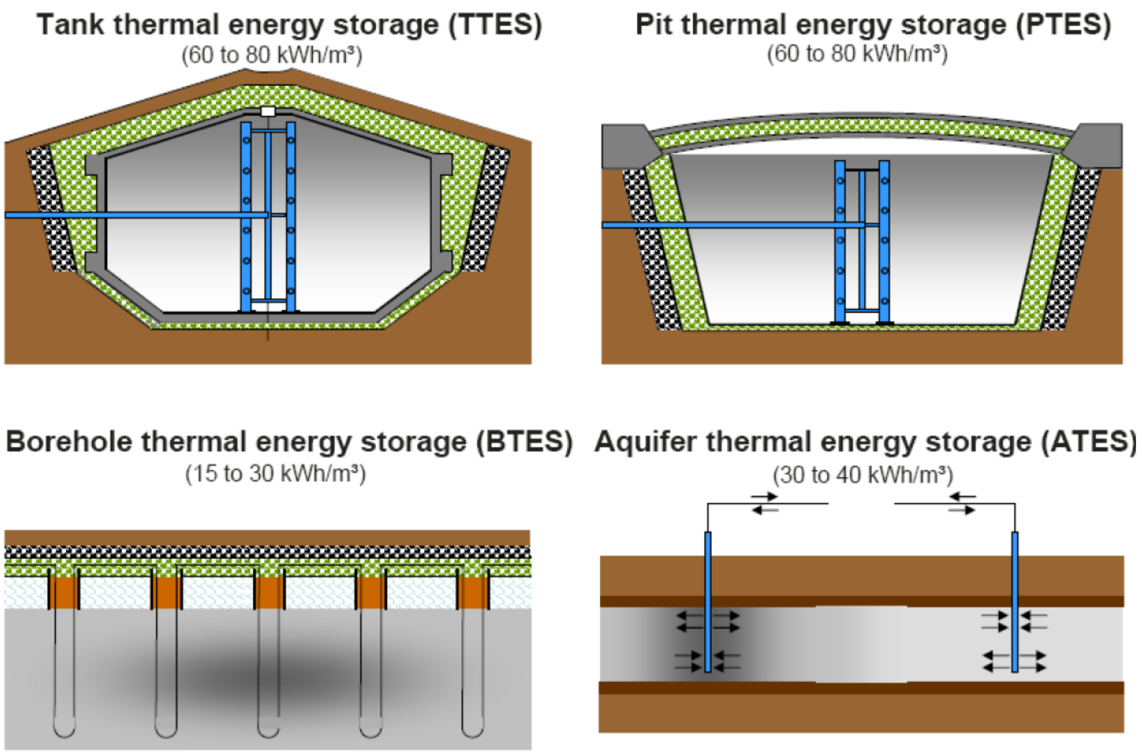


Figure 3 – Concepts of four different thermal energy storages. Figure reproduced from (Mangold, 2007).

Figure 3 from (Mangold, 2007) is reproduced to illustrate the principles of tank storage, water pit storage, borehole storage and aquifer storage.

Storing at low temperatures will imply a limited ΔT and thereby a limited energy density in the storage. This will also depend on the available heat supply (i.e. if high temperature heat is directly available or not).

Some large-scale storages occupy free space whereas others can be integrated with recreational areas. In case the storages must be located in the outskirts of (or outside) the city, transmission pipes have to be included.

3.2 Tank Thermal Energy Storages (TTES)

3.2.1 TTES technology description

Cylindrical steel tanks are also known as TTES, which is an abbreviation of tank thermal energy storage. This type of storage can be located above ground level, which is the most common case, but it can also be located below ground level. This is for instance seen in Germany, where tanks are sometimes used even as seasonal storages in connection to e.g. solar thermal, supplying smaller residential areas. If the storage is placed as steel tank above ground, it can be dominant in the landscape. If the storage is below ground level, it may be possible to use the area for other purposes.

Nearly 300 Danish district heating plants have heat accumulation tanks. These are not buried underground, but are made as insulated freestanding cylindrical steel tanks located next to the district heating plant. The average size is approx. 3,000 m^3 (PlanEnergi, 2013). The sum of all these is approximately 50 GWh. The tanks were initially installed together with CHP-plants to enable flexible production, optimizing the revenues from the electricity production. Due to the increased electricity production from wind turbines in Denmark, the annual operation hours of the CHP plants are decreasing. Now these tanks are in many cases utilized for solar heating plants, where they are sometimes supplemented by additional tank capacity.

The tank is typically made of stainless steel, concrete or glass-fiber reinforced plastic and contains water as storage material. Insulation of the storages is determined according to the environment and application. For steel tanks, 30 – 45 cm of mineral wool is typically used to keep heat losses at an acceptable level.

In most installations the temperature supplied to the storage is chosen to make it able to provide the supply temperature in the DH network. The temperature distribution in the storage is managed by a pipe system, shown in Figure 4 by the blue pipes. This system strives to keep the efficiency of the storage as high as possible. A vertical temperature distribution is seen in the steel tank, where the hot water is in the top. This is referred to as thermal stratification. It is possible for some tanks (with several outlets, even though they are not as many as shown in Figure 3) to extract heat at different heights. In such tanks water at the desired demand temperature level can be used (e.g. from the middle part of the tank) while maintaining high temperature water in the top of the tank if the temperature in the top of the tank is higher than what is needed. This is especially useful when operating with very large storages, where it is important to maintain a good thermal stratification, meaning a high temperature difference in the tank from top to bottom, in order to avoid having a large volume of too low temperature to be utilized directly in the network.

3.2.2 TTES economics of scale

Figure 4 shows the specific investment costs for cylindrical steel thermal storage tanks as a function of their volume. This storage technology shows very good economics of scale for tanks in the size of 0 – 5,000 m^3, but for much larger tank sizes the cost curve is quite flat. The data in the figure is for TTES in Denmark. No data is shown for TTES larger than 10,000 m^3 since this is quite uncommon although tanks up to 60,000 m^3 exist in Germany. The heat losses depend on the volume and the surface area of the tank, and are estimated to be in the order of 2% per week for 500 m^3 storages and 1% per week for 5,000 m^3 storages (PlanEnergi, 2013).

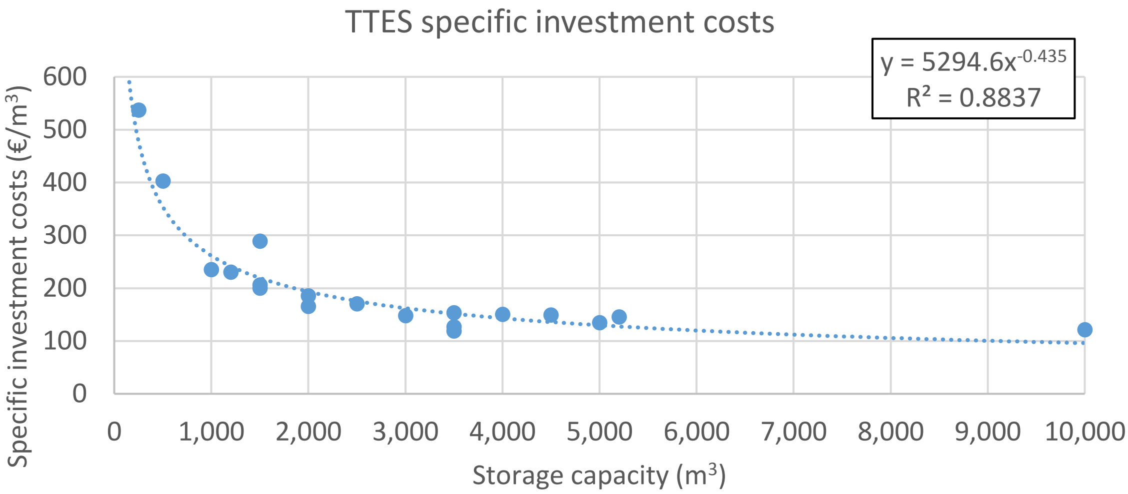


Figure 4 – Economics of scale for a few TTES storages in Denmark. Data from (Danish Energy Agency, 2014) and (PlanEnergi, 2013). The data was fitted using a power curve (see Equation 4). The fit shows good agreement with the data points.

3.3 Pit Thermal Energy Storage (PTES)

There are different technical concepts for seasonal heat storage. One of the concepts is the pit thermal energy storage (PTES), which has been developed since the 1980s at The Technical University of Denmark where a test storage was built. The first pilot demonstration storage was established in Ottrupgård, Denmark in 1995 (1,500 m^3) and the second pilot demonstration storage was constructed in Marstal, Denmark in 2003 (10,000 m^3). The first full scale storage was built in Marstal 2011 - 2012 (75,000 m^3), and the second full scale storage in Dronninglund, Denmark during 2013 - 2014 (60,000 m^3) – both in connection to large solar collector fields, covering around 40 - 50% of the district heating demand in each network. Pit thermal energy storage is a rather inexpensive storage form per m^3, developed in conjunction with solar heating. In Denmark 6 PTES are already in place and more are expected to follow.

3.3.1 PTES Technology description

A pit thermal energy storage is a large pit dug in the ground fitted with a membrane, typically of plastic, on the bottom and walls of the pit to keep the storage from leaking. Like for the TTES, the PTES also uses water as the storage medium. The pit is covered with an insulating lid, which floats on the surface of the water, to reduce the energy losses. The side walls and bottom of the storage are often not insulated because the ground soil has an insulating effect itself and the additional costs for improving the insulation are not feasible considering the reduced energy losses.

Figure 5 shows a cross section of the PTES and details of the construction. Liners are applied both as part of the lid and in the top of the PTES. The slope of the sides is relatively low, but depends on the local soil conditions.

Similar to TTES, PTES also have a vertical temperature distribution in the storage to increase the total efficiency of the storage. The same kind of system to manage this temperature distribution is also fitted here, and indicated in the blue pipes in Figure 3. The PTES requires a relatively large amount of area, compared to other thermal storage technologies.

For large-scale thermal storages this is the most common technology in Denmark, though not a large number of them have been established yet. PTES is currently used and planned for use as seasonal storage, primarily (but not only) in conjunction to solar thermal DH production. In Marstal there is in total 85,000 m^3 of PTES installed where the first 10,000 m^3 have been operated for more than a decade and the additional 75,000 m^3 was constructed in 2012. In the case of Marstal the solar fraction (i.e. the share of solar thermal energy for the district heating supply) is around 41% (Marstal District Heating).

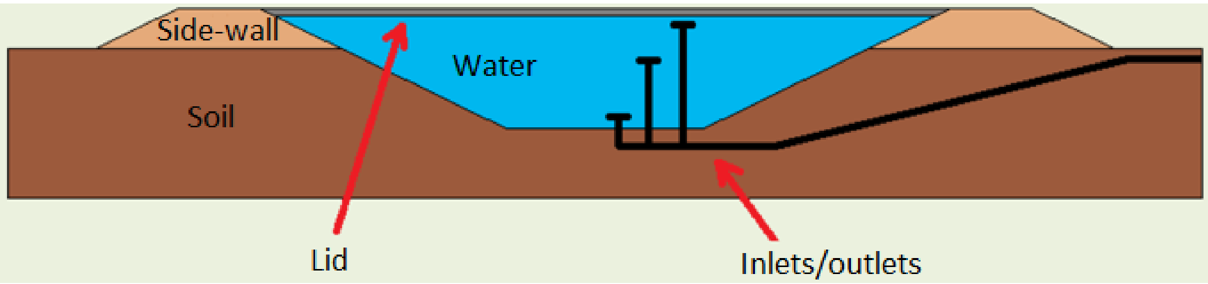


Figure 5 – The principle of pit thermal energy storage (PTES). Figure by PlanEnergi (PlanEnergi, 2013).

A PTES of 60,000 m^3 has been constructed in Dronninglund and in Gram a large PTES storage of 122,000 m^3 is constructed recently. Today the largest PTES is constructed in Vojens, with more than 200,000 m^3 capacity in connection to a solar heating system with a total collector area of 70,000 m^2. The seasonal storage ensures that around 40% of the annual district heating demand can be covered by solar heat.

For typical district heating temperature levels, the specific capacity of the storage is 60 - 80 kWh/m^3 similar to TTES. The heat losses depend on the temperature level in the storage, the insulation of the lid and the volume/surface-ratio, and whether a heat pump is used to discharge the storage. In general, the dimensioning of insulation is subject to economical optimisation, i.e. does it make more sense to invest in insulation or more solar collectors. A wide range is seen. Examples of storage efficiencies in the range of 80% to 95% have been seen.

Key points for pit thermal energy storage are choice of material and water chemistry. Water treatment – removal of salts and calcium, raise of pH to 9.8 – is important to reduce/avoid corrosion. In addition, choice of steel quality of the pipes is crucial to ensure long technical lifetime. The insulation material in the lid should be resistant to water in case of a leakage, so that the insulation effect is not lost. Leakages can be found and repaired by divers. A key component of the pit thermal energy storage is the liner. The technical lifetime of the liner depends on the temperature of the water – the higher the temperature the shorter the lifetime.

3.3.2 PTES Geometry – Considerations regarding design, soil balances etc.

When establishing a very large pit heat storage, for instance of 1 million m^3, it can be beneficial to consider establishing two pit heat storages of 0.5 million m^3 each and located just next to each other. In this case, the two storages are connected in series, which will correspond to having the two storages on top of each other. Typically, once a year, the connection is reversed. The benefits of this include

- Redundancy
- The two storages can be established and commissioned separately
- One storage can be taken out of service in case of maintenance
- The lifetime of the topliner increases
- Improved stratification

PTES are normally constructed as excavations designed as an inverted truncated pyramid, see Figure 5. The excavated land is laid in a bank around the excavation, thus achieving soil balance, and the volume of the storage is partly below and above the original terrain.

The sides and bottom of the storage are planned to avoid sharp stones, which can damage the liner. Then Geotextile lanes are laid to further protect the liner and eventually lanes off HDPE liner are welded together to provide a watertight surface. The lanes typically have a width of 6 - 7 m. The length of the lanes must be large enough to reach from the top to the bottom of the storage to avoid welding along the sides of the storage. The liner is held in drains/banks around the bearing as shown in Figure 6.

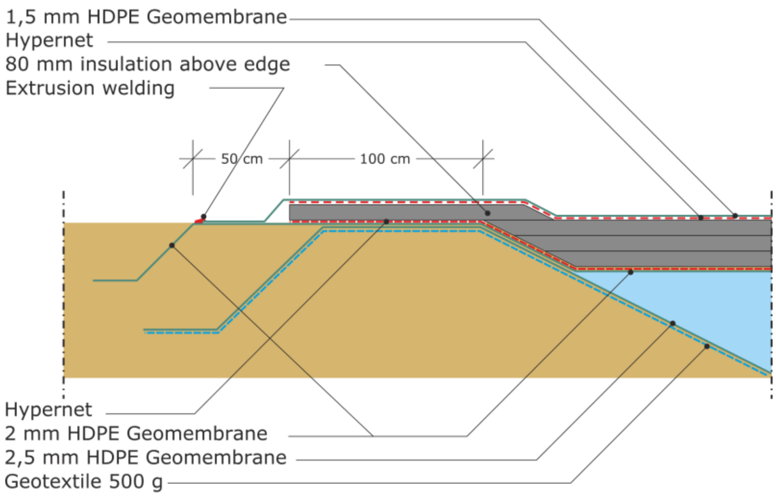


Figure 6 – Cut through the lid and lockers. The locking gates are channels dug free around the storage. In these channels, the ends of the liners are placed and then filled with soil that locks the liner (PlanEnergi).

Depending on the size of the storage, typically three tubes are introduced through the bottom or side of the storage to three diffusers placed in respectively the top, middle and bottom of the storage in order to move the water to and from the storage.

When the storage is filled with water, the work with the top is initiated, which typically consists of an HDPE liner floating on top of the water that is welded and pulled over the water surface so that the entire surface is covered. The bottom cover of the lid is locked as the sideliner fixed in the soil banks. At the top of the bottom line of the lid, a drain line is placed, then insulation, and at the top another drain line before closing the lid with an HDPE top liner. The top liner is welded to the bottom of the lid along the edge of the bearing. A number of vacuum valves are attached to the top line, which secures the liners against wind impact and, in combination with the drainage valves, ventilates the lower structure. An HDPE liner is not steam diffusion proof, and ventilation is therefore necessary to avoid build-up of moisture in the lid that destroys the insulation properties.

The lid is a major part of both the investment and the heat loss. The lid should therefore be as small as possible, which is achieved by making the (inner) slope as large as possible, as well as making the storage as deep as possible. Figure 7 shows the relative lid area (compared to a reference with a depth of 40 - 45 m and a slope of 1:2) as a function of water depth for a rectangular 0.5 million m^3 pit storage, for two different slopes of the storage sides. It is apparent that the higher the slope, the smaller the area (the red curve is below the blue curve). This means that for a given volume and a certain depth, a significant share of the lid area can be saved if the slope can be increased. The maximum slope is limited in practice by geotechnical conditions and/or working conditions in connection to establishment of the bottom/sideliner. It is difficult to have a steeper side than 1:2 (as ratio between height and width of the sides). It is also apparent that the greater the depth of water, the smaller the area (the curves fall to the right). However, the curves eventually flat out, so the gain is limited for water depths greater than respectively 30 m and 45 m approximately for the two slopes shown. However, the maximum water depth will usually also be limited by the groundwater level and the desired level of soil balance. Figure 8 shows possible shapes for PTES of two different depths.

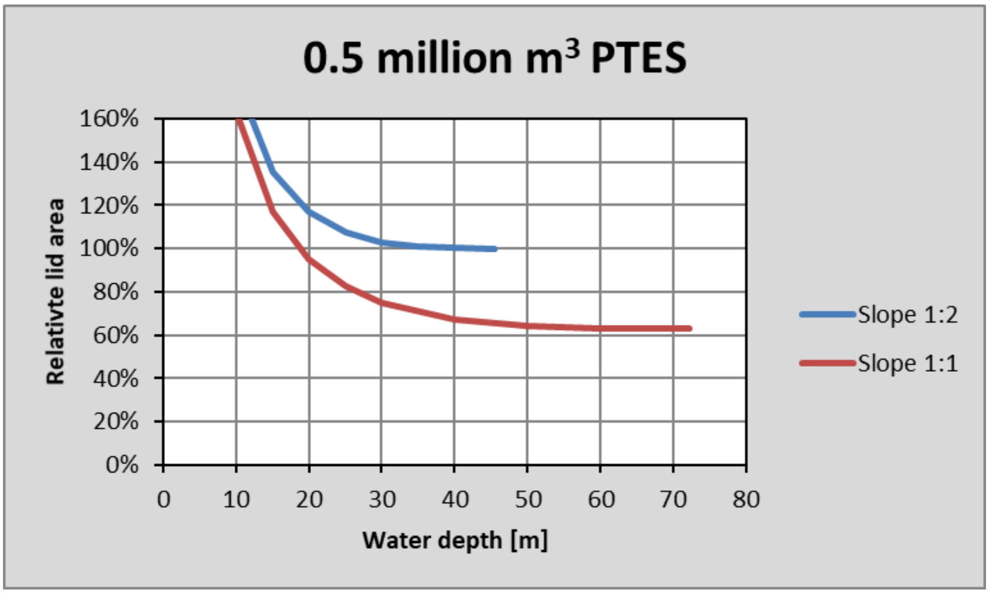


Figure 7 – Lid area relative to the area of a PTES with a depth of 45 m and a slope of 1:2 as function of water depth for a 0.5 million m³ PTES. The figure shows that for depths larger than approx. 35 m (1:2 slope) and approx. 50 m (1:1 slope), no reduction of the lid area is obtained.

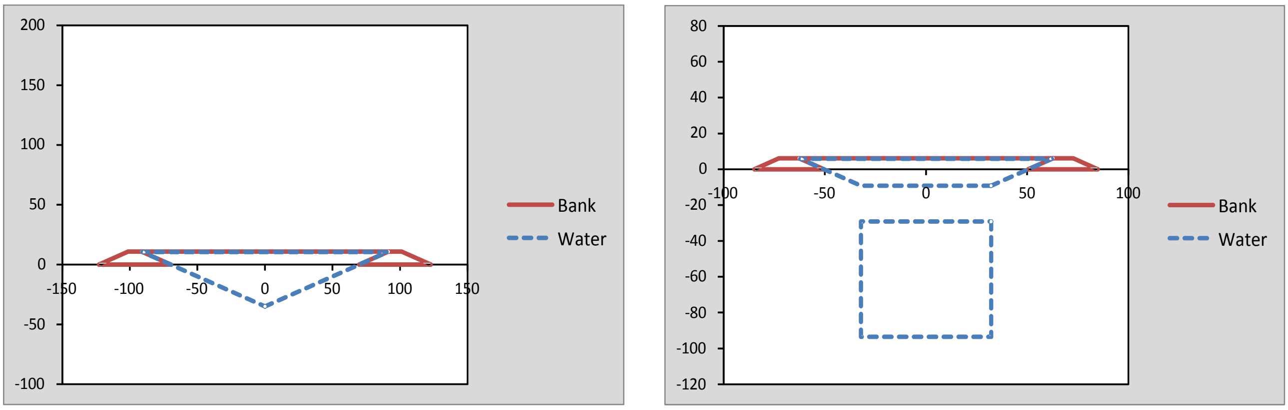


Figure 8 – PTES of water depths of approx. 45 (left) and 15 m (right). Notice the different scales on the secondary axis (sketch by PlanEnergi).

3.3.3 Soil balance

It will often be expensive for a pit heat storage if the excavated material is to be disposed of (if the storage is placed only under ground level) or if external material is to be supplied (if the storage is located above ground level). The surplus soil / soil deflection is shown as a function of the vertical position of the storage for a storage of 0.5 million m³ in Figure 9. If the storage is buried completely (the sketch to the right in Figure 10) the soil surplus is obviously approximately 0.5 million m³ (the complete water volume). If the storage is reversed across the terrain (the sketch on the left in Figure

10), approximately 1 million m^3 material needs to be added. The storage must be buried approximately 19 - 20 m down to achieve soil balance (where the red curve intersects the blue in Figure 9). The depth of the PTES has a rather large impact on the soil balance. In the given case, a change of depth by ±1 m changes the soil balance by around ±50,000 m^3 of material.

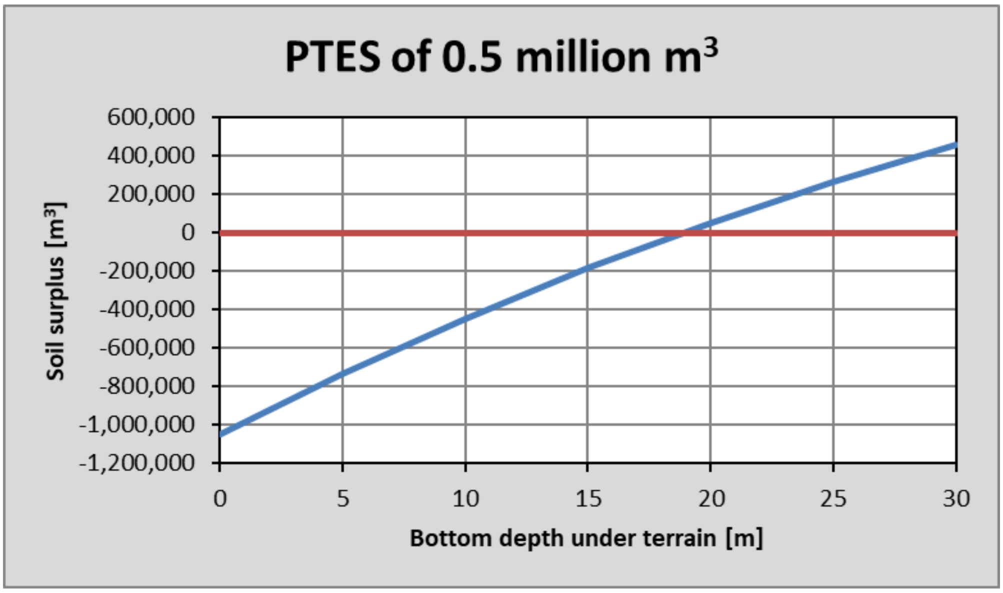


Figure 9 – Soil surplus as function of the bottom depth under terrain.

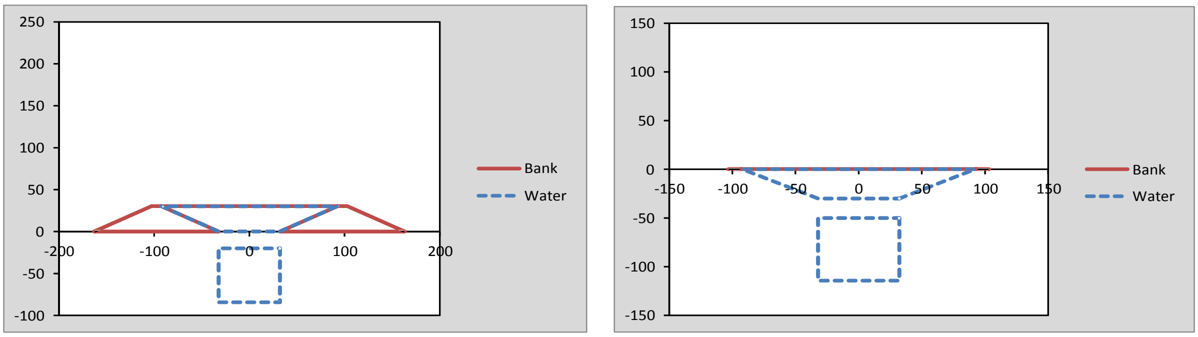


Figure 10 – PTES of the same volume above and under terrain. The water depth is 30 m in each case and the slope is 1:2 Notice the different scales on the secondary axis (sketch by PlanEnergi).

3.3.4 Storage depth

It is often the groundwater level that determines how deep the excavation can go. In addition, it is desirable that the storage is cooled as little as possible by flowing groundwater. Figure 11 shows that a hole depth below 19.7 m gives a water depth of 30 m, see sketch on the left on Figure 12. Similarly, a hole depth of 10 m gives a water depth of 19.3 m, and a hole depth of 5 m gives a water depth of 12.7 m. At the same time, it can be seen that the deeper buried underground, the smaller the lid area.

As mentioned previously, it will often be the conditions of the soil or the groundwater that will determine the depth under terrain.

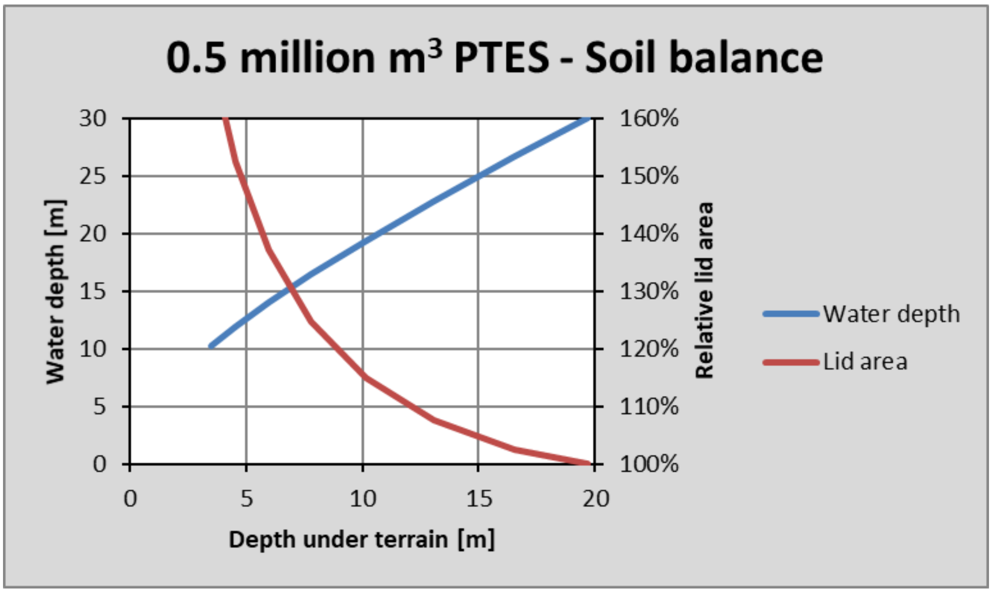


Figure 11 – Water depth and relative lid area as function of hole depth for PTES with soil balance.

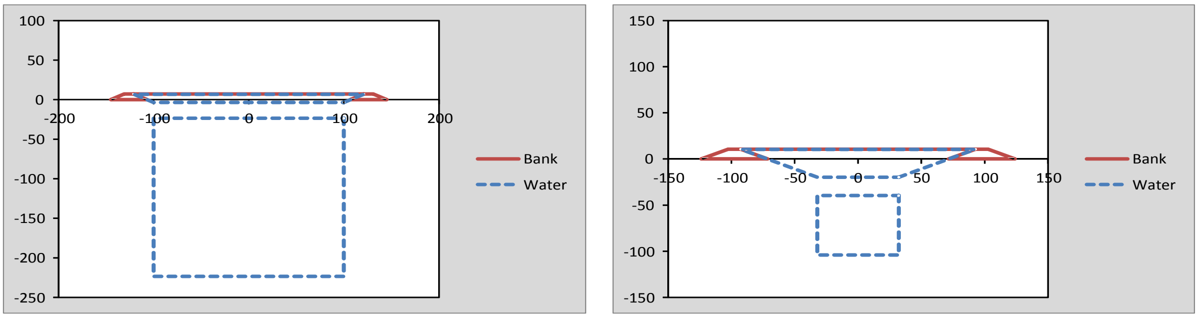


Figure 12 – PTES with water depths of approximately 10 and 30 m. Notice the different scales on the secondary axis (sketch by PlanEnergi).

3.3.5 PTES economics of scale and investments

Pit thermal energy storages have significant economics of scale benefits as shown in Figure 13. They are primarily suitable as large-scale facilities and the tendency has been that every new PTES that is constructed is larger than those already existing. For large-scale heat storage, PTES has considerably lower specific investment costs than TTES.

The total investment of a storage solution depends strongly on the geometry of the storage, which is shown in the previous sections but also factors as location and work salary. Especially the lid has a high price per area. Some estimated costs are shown in Table 3.1. The costs were collected in connection with a project by PlanEnergi for two storages of 0.5 million m^3 each.

Table 3.1 The specific investment costs for the main components of PTES systems.

Component	Value	Unit
Digging and rebuilding (chalk)	13	€/m³
Bottom and sides	27	€/m²
Lid (insulated with 300 mm Nomalén) (insulation 51 €/m²)	111	€/m²
Water (raw water 0.8 €/m³ + water treatment 1.9 €/m³)	3	€/m³

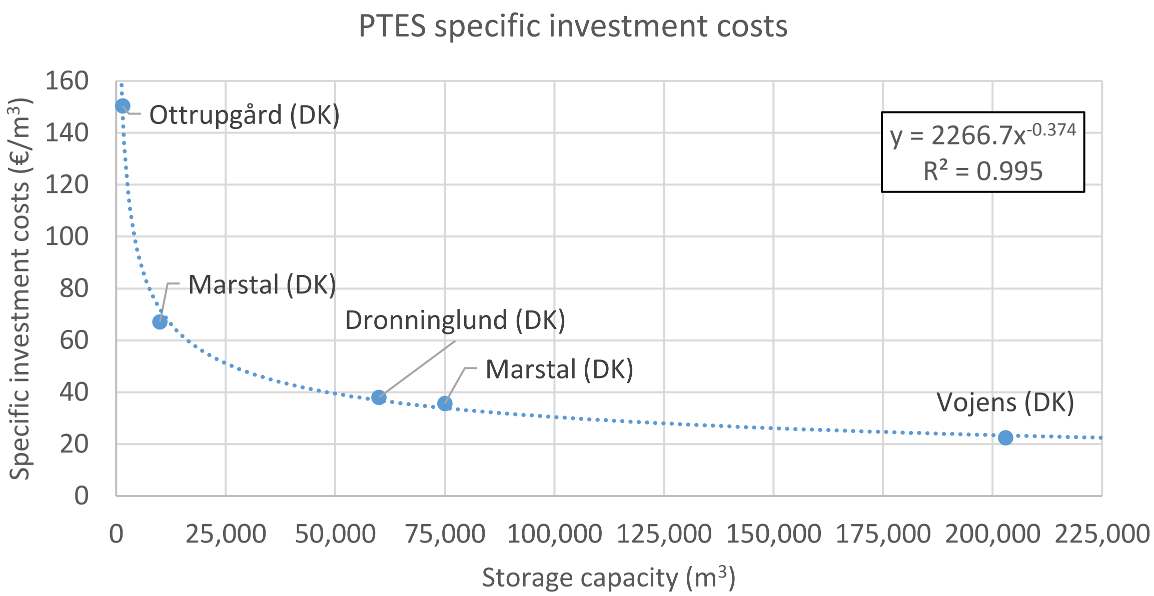


Figure 13 – Economics of scale for PTES systems. Data from (PlanEnergi, 2013) and (PlanEnergi, 2015). The data was fitted using a power curve (see Equation 4). The fit shows an excellent correlation with the data points.

3.4 Borehole Thermal Energy Storage (BTES)

3.4.1 BTES technology description

A borehole thermal energy storage (BTES) consists of a number of boreholes in the ground in which pipes are placed. The storage is charged by pumping hot water through the pipes in the boreholes, which then transmits heat to the ground surrounding the boreholes. The storage medium here is the soil surrounding the boreholes and not the water in the pipes which is just a transfer medium. There is usually a layer of insulation on top of the boreholes to reduce heat losses.

Figure 14 shows a cross-sectional and a three-dimensional drawing illustrating how the BTES is located in the ground. When discharging, cold water is pumped through the pipes in the boreholes and the stored energy in the ground is absorbed in the water.

A number of BTES facilities exist today in a number of countries, including Germany, Sweden, Canada, USA and Denmark. The first BTES in Denmark was constructed in 2012 and put in operation in Brædstrup for district heating supply in conjunction with a large solar thermal capacity. The facility consists of 48 boreholes of 45 m in depth with a total storage volume of 19,000 m^3 soil. At the time of construction, the Brædstrup BTES was the largest BTES facility for district heating in Europe.

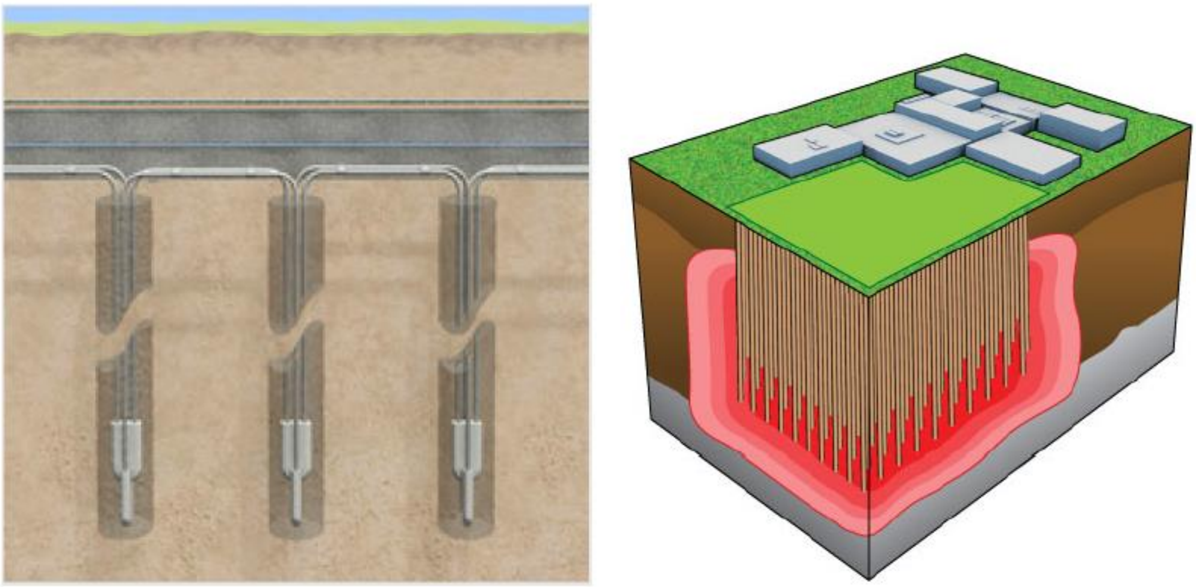


Figure 14 – Cross sectional drawing of a BTES and Three-dimensional drawing of BTES (www.bbeatty.com/geothermal.php).

The capacity of BTES can be anything between one borehole for the use of one single household to large-scale storages of several hundred boreholes. However, a single borehole for a single household is typically not used as a storage, but simply as ground heat source. In this case, energy can be extracted from the ground to supply heat pump evaporators at higher temperature levels than ambient air in winter and thus improve the seasonal performance factor (SPF) of the heat pump. Vice versa, the geothermal heat exchangers can be used for heat rejection of the chiller condensation energy at lower temperature levels than ambient air or cooling towers, which again improves the chiller energy efficiency ratio. The boreholes can also be directly used.

Direct use of thermal energy from the underground for building cooling or heating is a very efficient way to use underground heat exchangers (e.g. boreholes), as only electricity for energy distribution (pumps and fans) is required. The heat carrier media can be air or water brine. A specific cooling power in the range of 45 W/m was reached with an air-geothermal heat exchanger in an office building in Weilheim in Germany, whereas only 25 W/m were recorded in a brine-based system. Data for the power as a function of ambient temperature for this system is shown in Figure 15. Data for the power as a function of the brine temperature for a brine-based system is shown in Figure 16.

In (Biermayr, 2013), a 2 year simulation of a U-shape ground heat exchanger designed for seasonal storage of solar heat shows that specific charging powers of over 130 W/m are reached, because of the high temperature difference between the ground temperature (12 °C in average) and the outlet temperature of the solar field of 70 °C. With a discharge temperature of -2 °C (heat pump evaporator), the specific discharge power of only 40 W/m are reached. The storage efficiency can be increased with geometrical distribution of several ground heat exchangers. The results can be found in Figure 17.

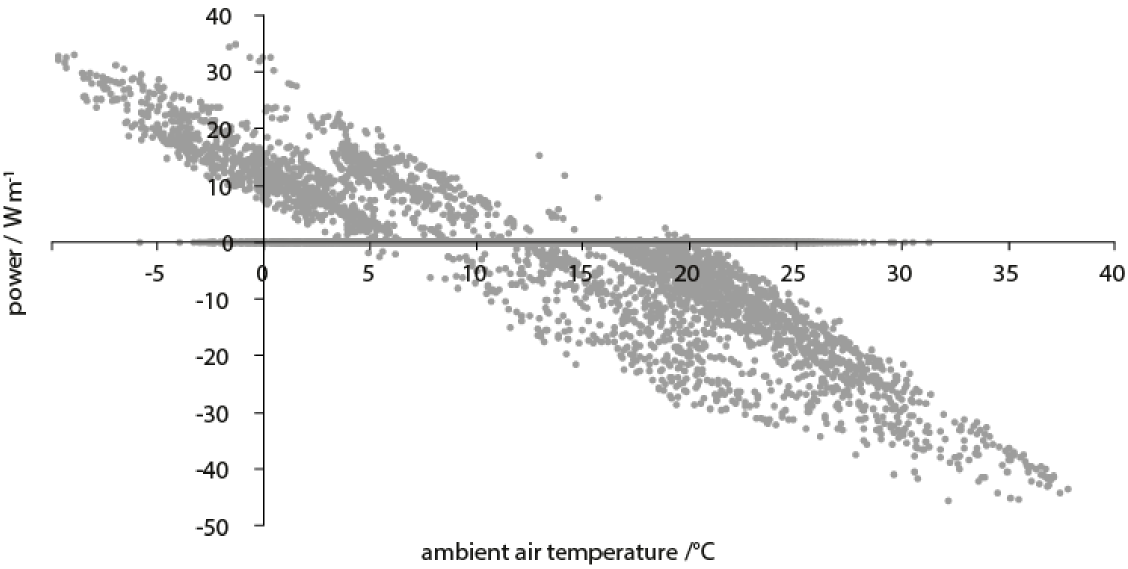


Figure 15 - Power of the earth-to-air geothermal heat exchanger in the Weilheim office building as a function of ambient air temperature, which corresponds to the inlet temperature to the ground heat exchanger.

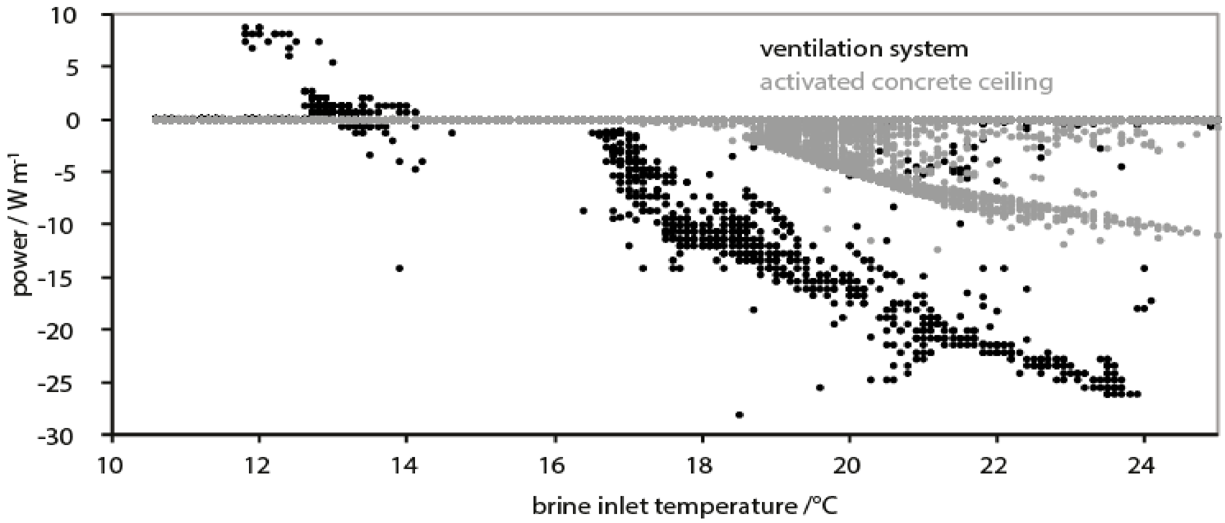


Figure 16 - Measured geothermal power in 2006 as a function of brine inlet temperature to the ground (office building in Freiburg).

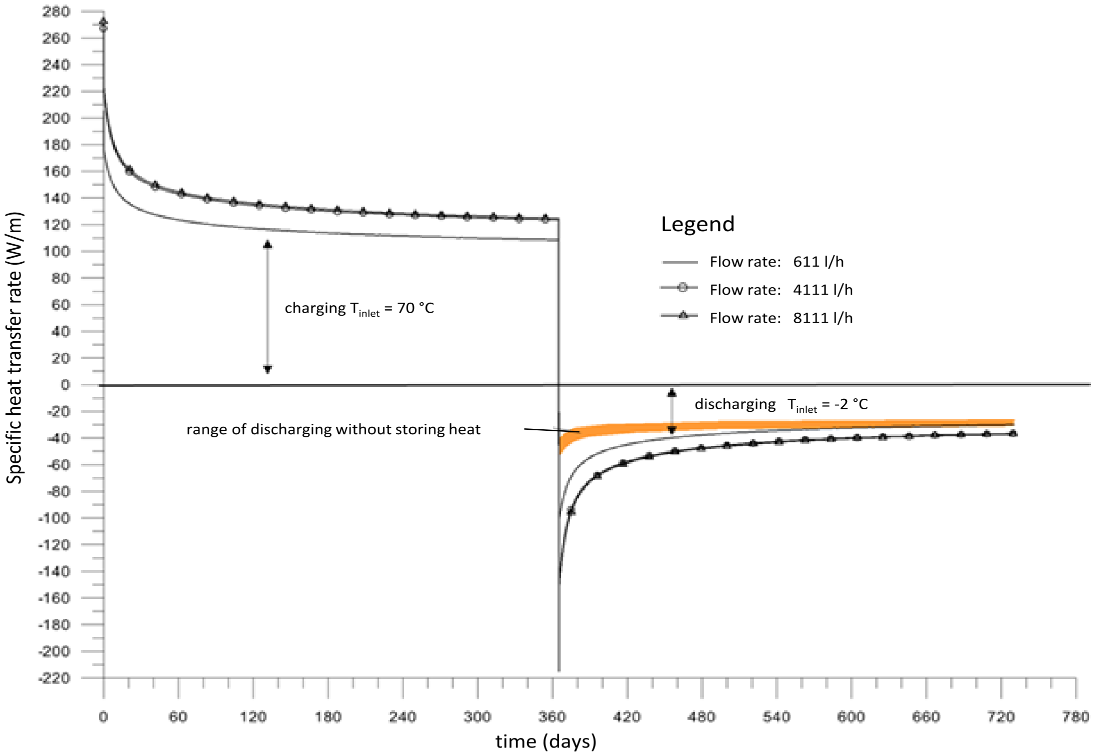


Figure 17 - Specific heat transfer rate per metre of borehole length of a common U shape double pipe ground heat exchanger for 2 years. Year 1: charging period with a temperature level of 70 °C; year 2: discharge with a temperature level of -2 °C. The orange line represents the discharge specific power without storing heat previously (Biermayr, 2013).

(Biermayr, 2013) shows that the combination of a BTES with a short term TTES can be financially interesting by increasing the direct use of solar heat. The TTES can act as a buffer between variations in solar heat production (varies from day to night) and the borehole storage (which cannot be charged as fast as the solar heat is produced). Also for large-scale installations, experience shows that the best economical performances of BTES are achieved when a buffer tank is included in the system.

The most suitable geology for BTES is saturated soils with no or very limited groundwater flow and a high heat capacity. The specific capacity of the systems is estimated to being 15 - 30 kWh/m^3 of storage material for typical district heating temperature levels (PlanEnergi, 2013). The efficiency depends on the size of the storage. For small systems, the efficiency can be as low as 60% where for large systems of above 100,000 m^3 the efficiency can reach 85 - 90%.

The charge and discharge effect is limited by the convection from or to the storage material in the ground and the transferring medium in the ground pipes. This is why BTES mainly is used for base load capacity. The investment costs are sensitive to the ground properties of the location where the storage is to be constructed. Since it requires many boreholes for large facilities, any difficulty in drilling the boreholes can increase the investment costs significantly. Compared with other storage options (e.g. PTES) examples of pro and con arguments for BTES are: BTES does not take up a large area (since the top surface can be used for other purposes). The heat cannot be extracted at a sufficiently high temperature level to supply conventional district heating directly. Hence a heat pump is needed even if the heat is injected at higher temperatures, and an exergy loss is thereby introduced. The outlet temperature issue becomes less important in the context of the (lower) FLEXYNETS network temperatures.

3.4.2 BTES economics of scale

The storage volume of borehole thermal energy storage is not as well defined as for TTES and PTES. It is often assumed that 3 m^3 of soil volume BTES are equivalent to 1 m^3 of water storage volume because the soil has a lower specific heat capacity than water (Mangold, 2015), though in practice this will depend on the local conditions. After making this conversion from soil volume to water equivalents, BTES storage volume can be compared directly with the volumes of TTES and PTES.

As shown in Figure 18, BTES does not have as well-defined economics of scale as TTES and PTES. The specific investment cost is around 40 €/m^3 water equivalent for four out of the five systems in the examples used. An increased amount of data points would provide a more reliable estimate of the economics of scale of BTES. The investment cost for such systems is also location-specific, as it relies on the geological suitability of the soil for drilling the holes and on the composition and permeability of the soil with regard to heat exchange and storage.

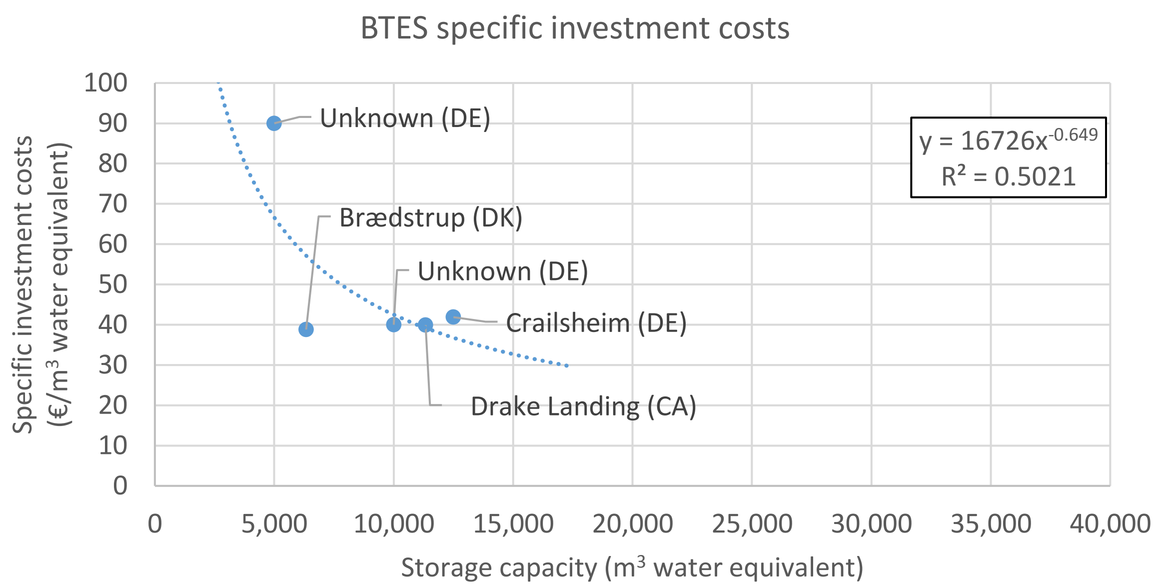


Figure 18 – Economics of scale for BTES systems. Data from (PlanEnergi, 2013) and (CIT Energy Management, 2011). The data was fitted using a power curve (see Equation 4). Note that the fit is somewhat unreliable due to the large scattering of the data points.

Detailed capital costs were available for the two 134 m boreholes of the heat pump system in Ostfildern in Germany, shown in Figure 19. The investment costs correspond to 129 €/m of earth heat exchanger with the drilling costs accounting for about 50 % of the total costs. Other project examples (e.g. systems from Spain) have significantly lower specific investment costs (about 50 - 60 €/m).

A study of the Ministry of the Environment, Climate Protection and the Energy Sector Baden-Württemberg from 2011 showed a linear correlation between investments and ground heat exchanger length with a slope of 58 Euros per metre, shown in Figure 20. The specific cost, reported for Austria in (Biermayr, 2013), for boreholes under 150 m deep is around 40 to 50 €/m by using hydraulics drilling technic. This price does not include taxes nor equipment such as pipes.

drilling:	17 903 €	52%
legal certification:	1 553 €	4%
4 double U-tubes:	3 076 €	9%
brine package:	3 809 €	11%
2 pumps + membrane expansion:	966 €	3%
connection tubes:	2 496 €	7%
brine distribution:	928 €	3%
connections/ valves:	3 875 €	11%

Figure 19 - Investment costs of the vertical heat exchangers at the youth centre installation in Ostfildern.

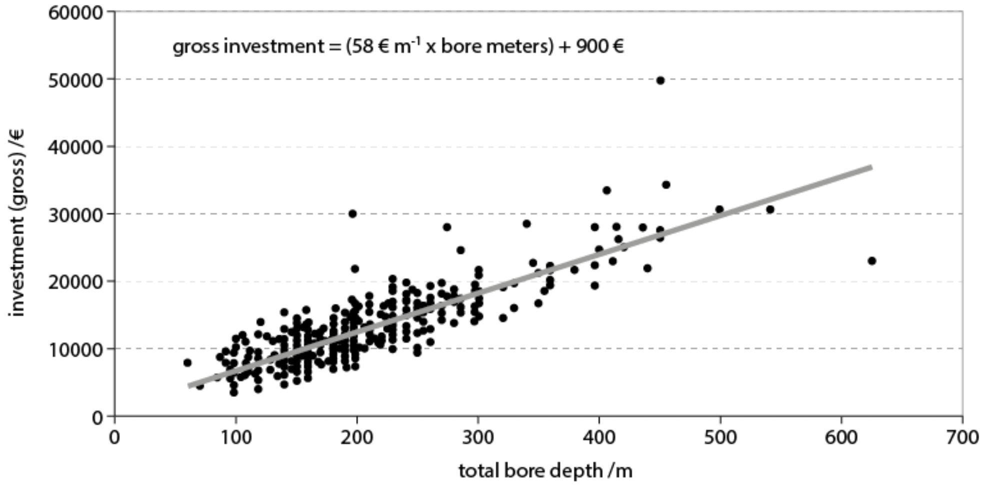


Figure 20 - Gross investment costs for vertical earth heat exchangers (examples of investment in boreholes only).

3.5 Aquifer Thermal Energy Storage (ATES)

3.5.1 ATES technology description

In aquifer thermal energy storage (ATES) systems, two (or multiples of two) separate wells are drilled into an underground groundwater reservoir (aquifer) for seasonal storage of thermal energy. One of the wells is used for heat storage and the other for cold storage. Favourable geological conditions are a prerequisite for ATES systems, which require a high yielding aquifer. The working principle of the storage system is as follows: In winter, water is pumped from the warm well for use as a heat source for a heat exchanger or a heat pump. Cooled water from the heat exchanger or heat pump is pumped into the cold well. In summer, the process is reversed. Water from the cold well is pumped up for cooling and heated water from a heat exchanger or heat pump is pumped into the warm well. In this way, the ATES is a closed system as the water from the aquifer circulates in a loop without any net consumption of groundwater. The operation principle of ATES during summer and winter is illustrated in Figure 21.

ATES systems are low-temperature storages. In fact, it is most often the demand for cooling (rather than heating) that motivates the investment in ATES systems and the systems can be economically feasible even without being used for heat supply (Pedersen, 2014). Typical temperature ranges for the reservoirs are 7-16 °C for the cold well and 10-18 °C for the warm well, with the temperature depending on the seasonal state of charge of each well. In most countries, there are regulations on how warm the water that is pumped into the underground may be; in Denmark it is e.g. not allowed to pump water that is warmer than 25 °C into the ground, with the monthly average not exceeding 20 °C.

The typical storage capacity of one well is 500 MWh and the typical injection and extraction power of one well is 1 MW. The investment costs for the system is largely power related and not storage capacity related. The storage efficiency can be as high as 90% (Snijders, 2017). The ATES technology is rather mature and has been widely used in the Netherlands, Belgium, Sweden and Germany since the 1990s. In the Netherlands alone, there are over 1,500 ATES systems in operation.

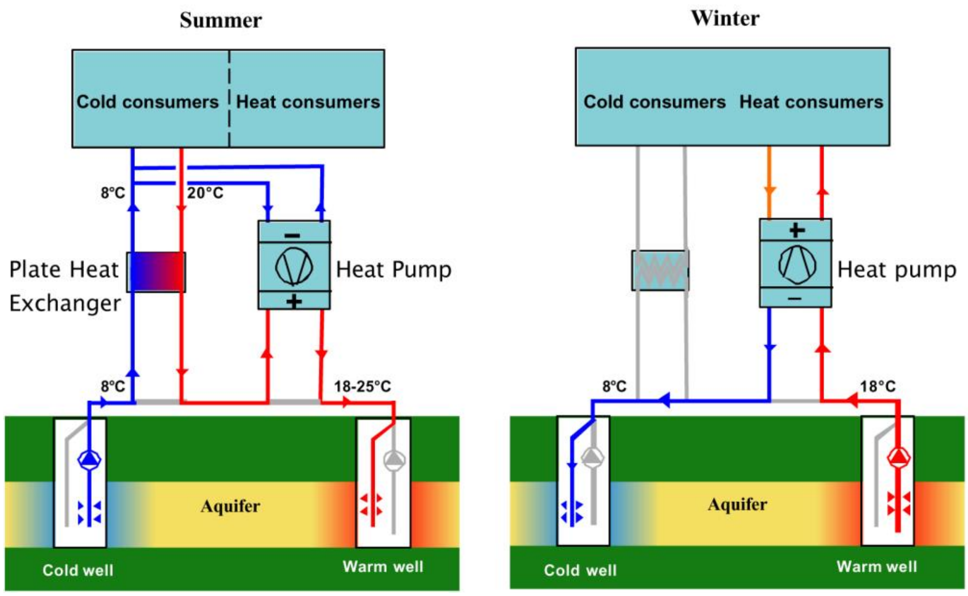


Figure 21 – Principle drawing of ATES (Pedersen, 2014).

3.5.2 ATES economics of scale

The economics of ATES systems are highly dependent on the geological conditions at each specific site, in particular on the water yield from each well and on the ΔT of the storage. As shown in Figure 22, the specific investment cost remains almost constant for different storage capacities. The economics of scale for ATES systems are not particularly attractive, because ATES systems are modular in nature, with each borehole pair yielding similar power and storage capacity. A doubling of power therefore requires a doubling of the number of wells.

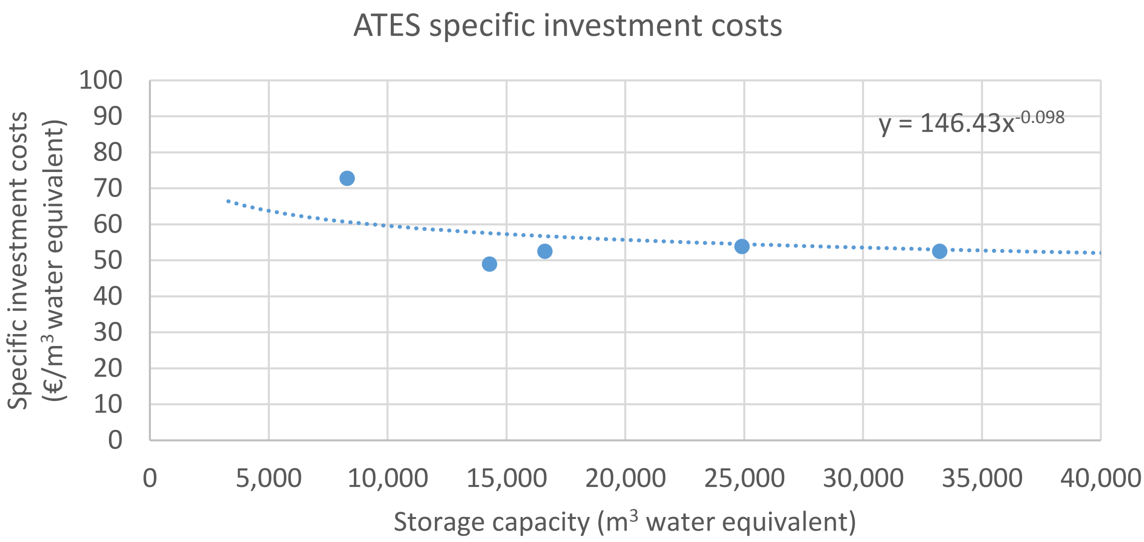


Figure 22 – Economics of scale for ATES systems. (Data from PlanEnergi, 2013) and (IFTech, 2017). Here, an aquifer with an average yield (50 m^3/h per well) and a ΔT of 10 K are assumed. The data was fitted using a power curve (see Equation 4). Due to the small number of available data points the fit is associated with some uncertainty.

3.6 Investment costs depending on storage temperature levels

One thing to consider is whether it is more feasible to store at low temperatures (e.g. because the investment in insulation can be reduced) or to store at high temperatures because this will mean higher energy density and thereby a smaller storage volume for the same energy content. This will of course depend on the available heat supply (i.e. high temperature directly available or not).

The specific investment costs for TTES, PTES, BTES and ATES as a function of the temperature difference ΔT are plotted in Figures 23, 24, 25 and 26, respectively. The plots are produced using Equation 5 with the fit parameters a and b from Figure 4, Figure 13, Figure 18 and Figure 22 for each respective storage technology. In each figure, the costs are plotted for four different storage capacity examples.

The temperature difference has a large impact on the specific investment costs, and more so as the value of ΔT decreases. For example, in the case of TTES, the specific investment costs roughly double when going from ΔT = 50 K to ΔT = 15 K, and double again when going from ΔT = 15 K to ΔT = 5 K. It is therefore clear that thermal storage quickly becomes expensive when the difference between maximum and minimum storage temperature is lower than 15 - 20 K. Large-scale thermal storages may be feasible at such low values for ΔT, as envisioned in the FLEXYNETS concept, if the increase in investment costs (compared to conventional district heating networks) can be accepted. In case such higher storage investment costs are unacceptable, large-scale storage may still be viable if inexpensive surplus heat is available at higher temperatures (and within a reasonable distance from the storage).

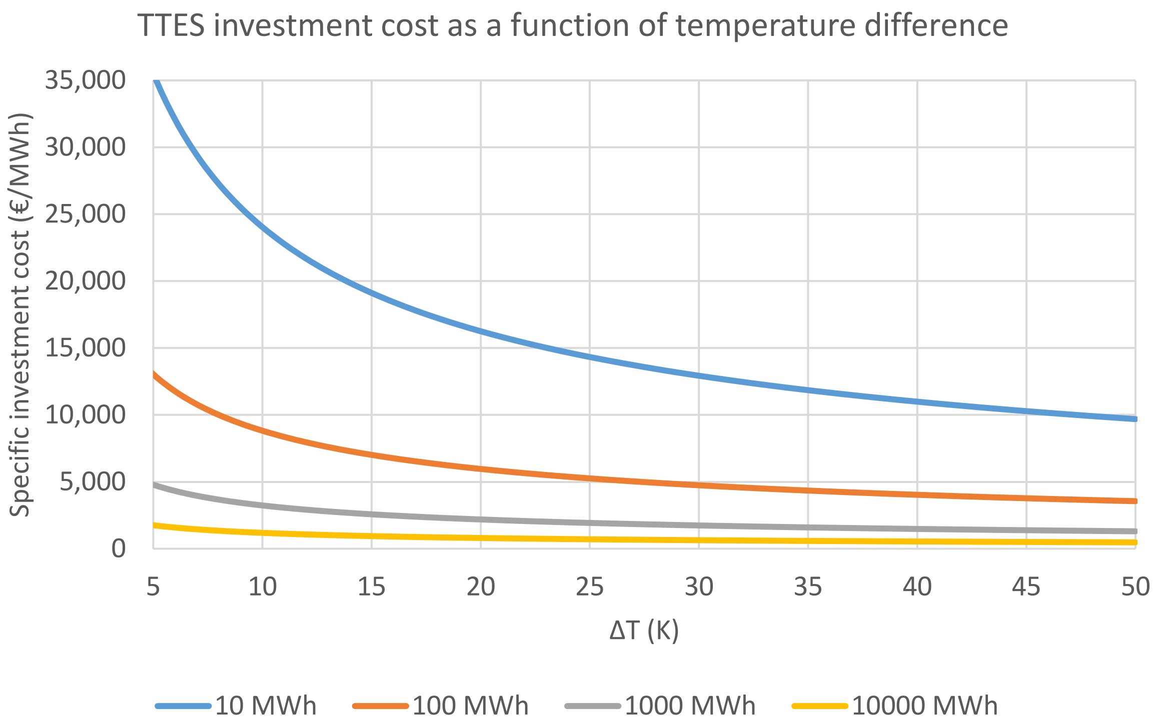


Figure 23 – The specific investments costs for TTES systems as a function of the maximum temperature difference in the storage, plotted for four different storage capacities.

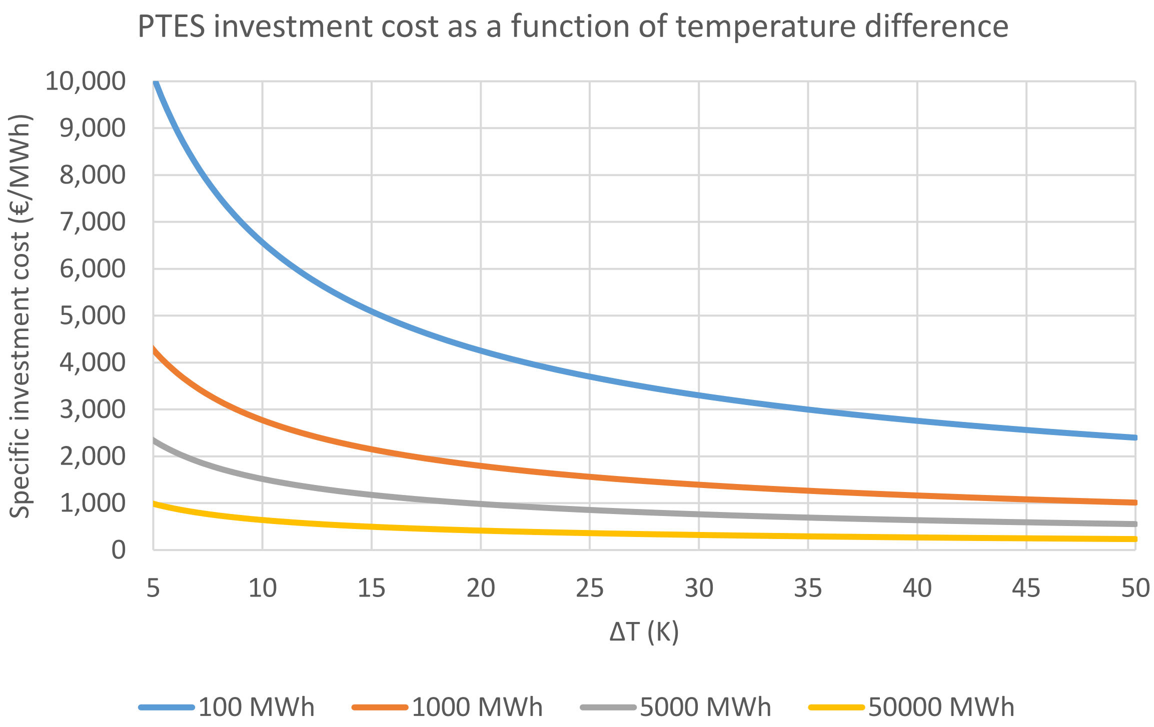


Figure 24 – The specific investments costs for PTES systems as a function of the maximum temperature difference in the storage, plotted for four different storage capacities.

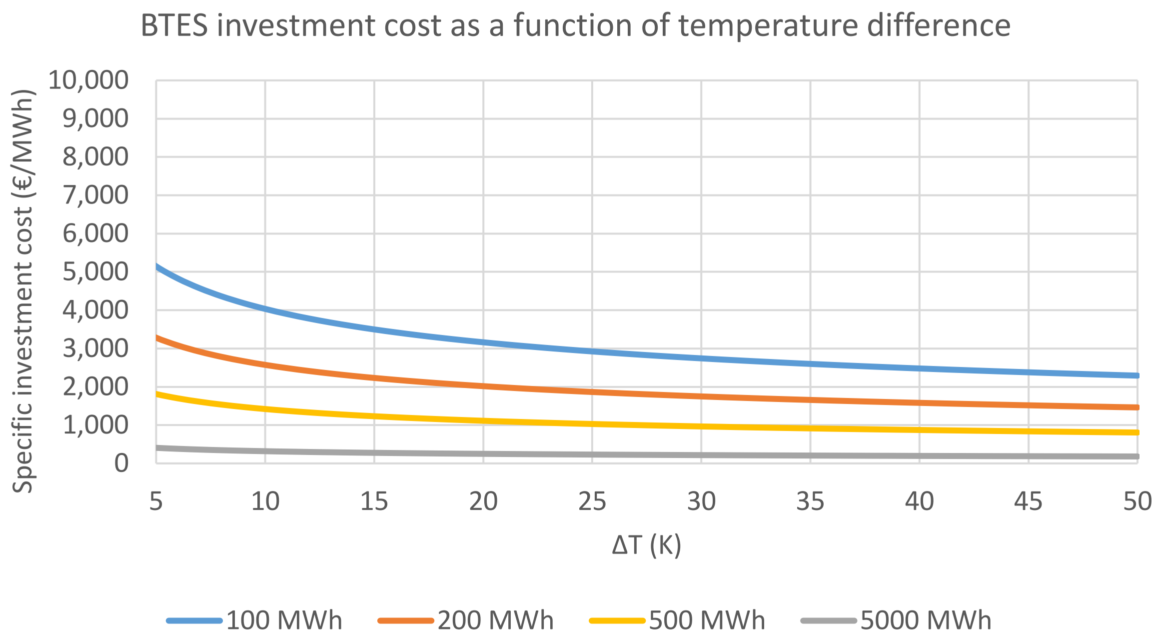


Figure 25 – The specific investments costs for BTES systems as a function of the maximum temperature difference in the storage, plotted for four different storage capacities.

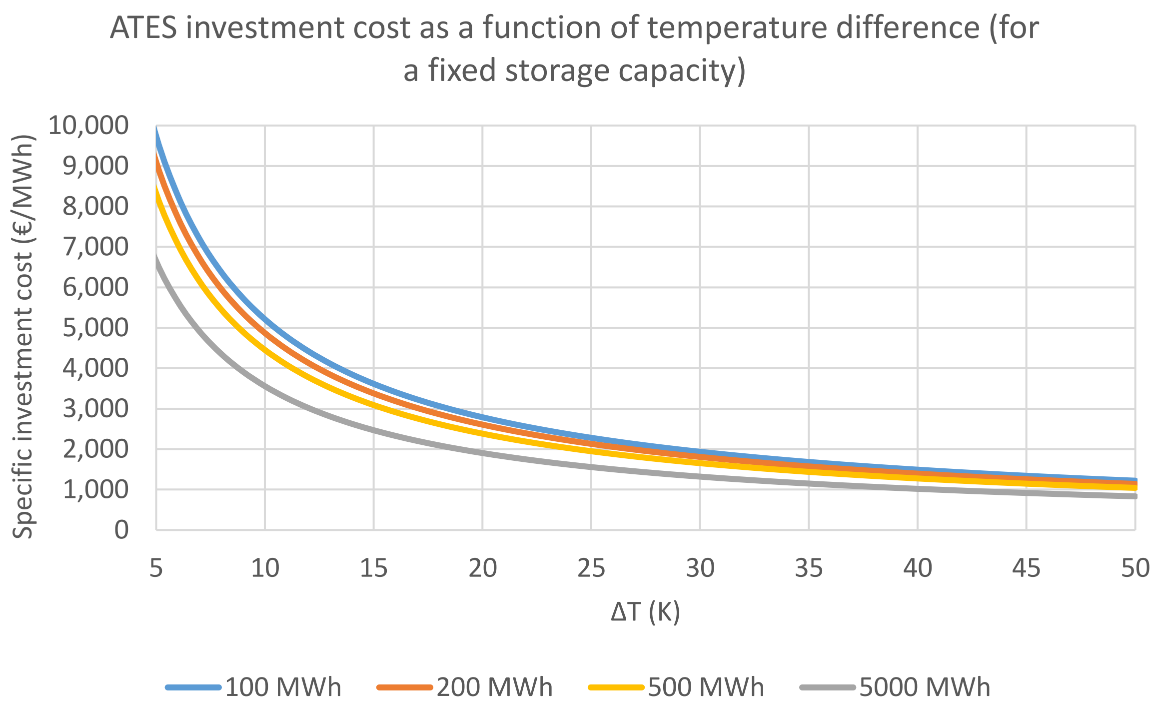


Figure 26 – The specific investments costs for ATES systems as a function of the maximum temperature difference in the storage, plotted for four different storage capacities.

3.7 Summary and comparison of storage types

In Table 3.2, the key parameters mentioned in the sections of the investigated storage technologies are summarized to give an overview and comparison between the technologies.

For large-scale TES, PTES has the advantage of lower specific investment costs compared to TTES, though they have many similar characteristics. They both use water as storage medium, have relatively high efficiencies and high charge/discharge capacities. The area requirements are the most significant disadvantage of PTES. BTES can be implemented almost independent of the geological properties (though these will affect the cost). An issue with BTES is that it has a relatively low charge/discharge capacity, which can be a problem depending on the specific application for it to be used in. ATES has the advantage of being able to supply both heating and cooling, and has relatively low costs compared to alternative cooling options. ATES systems are, however, only able to store at low temperatures and with a low ΔT.

Table 3.2 – A summary of the key properties for TTES, PTES and BTES. Reproduced from (Solites, 2012) and from (PlanEnergi, 2013).

Type	TTES	PTES	BTES	ATES
Storage medium	Water	Water (Gravel-water[1])	Soil surrounding the boreholes	Groundwater in aquifers
Specific capacity [kWh/m^3]	60 - 80	60 - 80 30 - 50 for gravel-water	15 - 30	30 - 40
Water equivalents	1 m^3 storage volume = 1 m^3 stored water	1 m^3 storage volume = 1 m^3 stored water	3 - 5 m^3 storage volume = 1 m^3 stored water	2 - 5 m^3 storage volume = 1 m^3 stored water
Geological requirements	• stable ground conditions • preferably no groundwater • 5 - 15 m deep	• stable ground conditions • preferably no groundwater • 5 - 15 m deep	• drillable ground • groundwater favourable • high heat capacity • high thermal conductivity • low hydraulic conductivity ($k_f < 10^{-10}$ m/s) • natural ground-water flow < 1 m/a • 30 - 100 m deep	• high yield aquifer

[1] Water is preferred thermodynamically. Gravel-water can be used, if the surface is used for other purposes such as parking.

Application	Short-time/ diurnal storage, buffer storage	• Long-time/ seasonal storage for production higher than 20,000 MWh • Short time storage for large CHP (around 30,000 m^3)	Long-time /seasonal for DH plants with production of more than 20,000 MWh/year	Long-time /seasonal heat and cold storage
Storage temperatures [°C]	5 - 95	5 - 95	5 - 90	7 - 18
Specific investment costs [EUR/m^3]	110 - 200 EUR/m^3 (for TTES above 2,000 m^3)	20 - 40 EUR/m^3 (for PTES above 50,000 m^3)	20 - 40 EUR/m^3 (for PTES above 50,000 m^3 water equivalent incl. buffer tank)	50 - 60 €/m^3 (for ATES above 10,000 m^3 water equivalent) Investment costs are highly dependent on charge/discharge power capacity
Advantages	High charge/discharge capacity	• High charge/discharge capacity • Low investment costs	Most underground properties are suitable	• Provides heat and cold storage • Many geologically suitable sites
Disadvantages	High investment costs	Large area requirements	Low charge/discharge capacity	• Low temperatures • Low ΔT

Figure 27 shows a summary of the economics of scale data for TTES, PTES and BTES from Figures 4, 13, 18 and 22 respectively. Figure 28 shows the same, but per unit of energy content instead of volume. For storing 100 MWh of heat or more, PTES is more cost effective than TTES. For storing 200-400 MWh of heat, BTES seems to be similar or slightly less expensive than PTES. The suitability of the technologies of course also depends on the time scale of the storage, i.e. if it is intended as a daily/weekly storage or a seasonal storage.

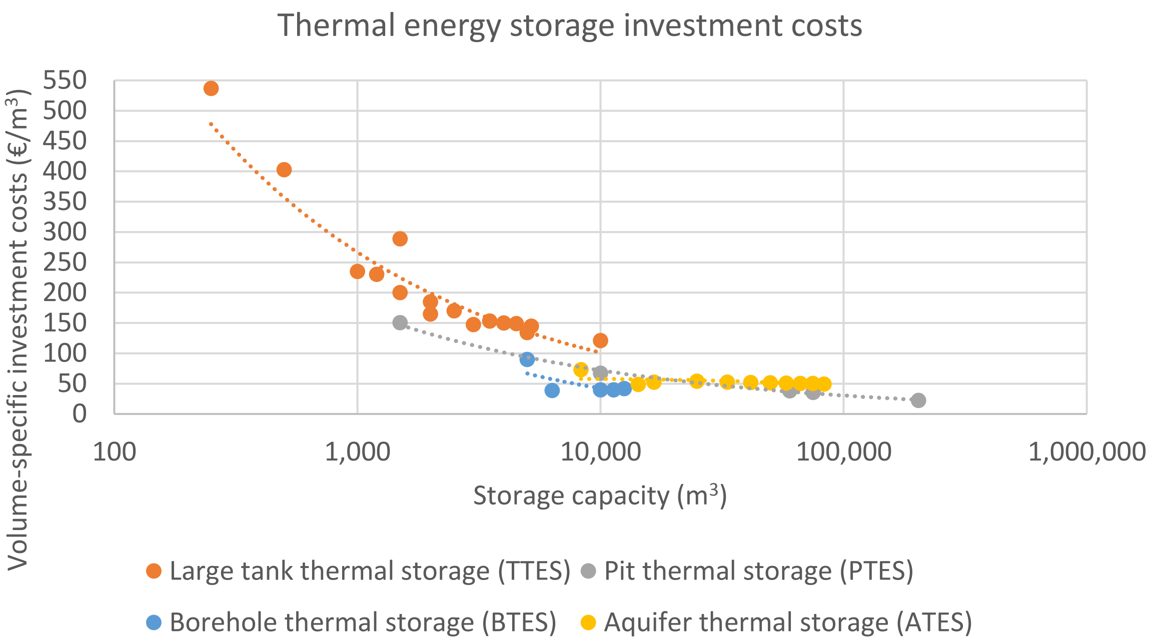


Figure 27 – A comparison of the economics of scale (on a volume basis) for TTES, BTES, PTES and ATES. Note the logarithmic scale of the primary axis.

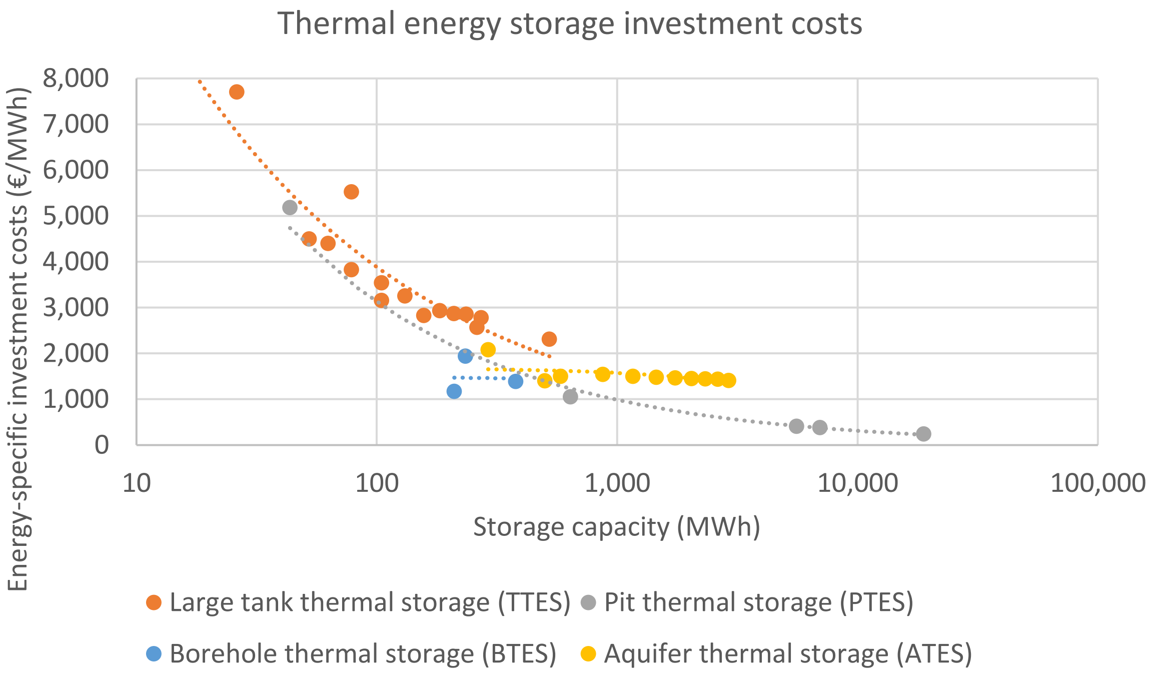


Figure 28 – A comparison of the economics of scale (on an energy basis) for TTES, BTES, PTES and ATES. Note the logarithmic scale of the primary axis.

4 Surplus heat sources and transmission pipelines to storages

One of the advantages of FLEXYNETS compared to conventional district heating is that the low temperatures in the FLEXYNETS network makes it possible to utilize surplus heat from a wider variety of sources than possible in conventional DH.

In case surplus heat is available, it is unlikely that the surplus heat supply pattern matches the heat demand pattern in the FLEXYNETS network. For a flexible utilization of the surplus heat, a heat storage could be established. Due to the low value of ΔT in the FLEXYNETS network and the inverse-proportional dependence of both the storage volume and the storage investment costs on ΔT, it may not be feasible to store heat at the FLEXYNETS operating temperature. It may be more beneficial to store the heat at higher temperatures, i.e. at the surplus heat source temperature, to take advantage of the larger ΔT between the surplus heat and the FLEXYNETS return temperature. Such a heat storage may be located either close to the location of the surplus heat source or close to a FLEXYNETS heat injection point.

The feasibility of utilizing surplus heat (in case it is available) depends highly on the distance between the surplus heat source and the FLEXYNETS network. If the surplus heat is not available within the area of the network, this requires a transmission pipeline connection between the two. However, even for a free supply of surplus heat, the value of this heat must outweigh the cost of constructing a transmission pipeline for the surplus heat in order for the utilization to be beneficial. This puts a limit on how far away from the FLEXYNETS network the surplus heat can be sourced.

4.1 Transmission pipeline cost

In Figure 29 the specific costs for district heating pipelines in outer-city areas are shown as a function of the nominal diameter of the pipes. The costs are shown for the case of steel pipes for normal district heating temperatures (insulation class 3) and for steel pipes suitable for the FLEXYNETS temperature levels (insulation class 1). It should be noted that the pipeline cost calculations described here are only utilized for calculating the costs of transmission pipelines for transmitting surplus heat directly from a source to a large-scale thermal energy storage, and not for calculating the costs of distribution pipelines within the FLEXYNETS network itself. The distribution pipelines in the FLEXYNETS network itself are not included in this report.

In Figure 30 the required nominal diameter for the pipes is shown as function of the energy flow through the pipes, assuming conventional water pumping velocities in district heating networks. The difference between the required diameter in conventional district heating systems and in the FLEXYNETS concept can be explained by the low value of ΔT in FLEXYNETS (10 - 15 K) compared to conventional DH (40 K). As ΔT decreases, the amount of water that must be transmitted to supply the same heating power increases (although this is partly compensated by the fact that a part of the thermal energy delivered by the FLEXYNETS consumers is provided in the form of electrical energy from the local heat pumps).

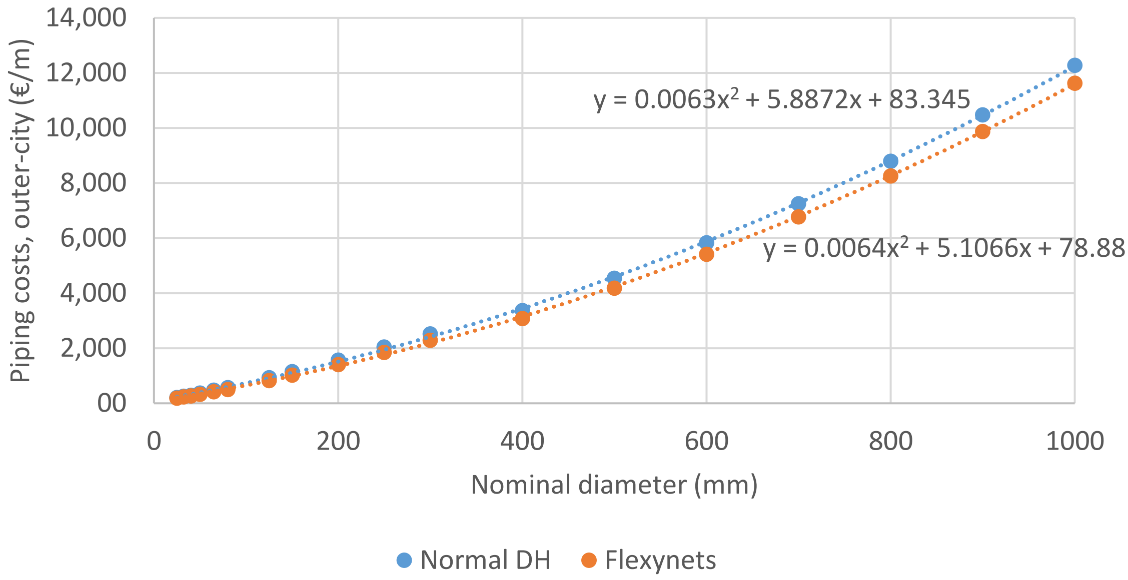


Figure 29 – The length-specific district heating piping costs, including pipe installation, shown as a function of the nominal diameter of the pipes. The values apply for outer-city areas. The data used for the figure is the same as used for the task 3.1 report in the FLEXYNETS project. The data has been fit with 2nd degree polynomials, which show a very good correlation with the data.

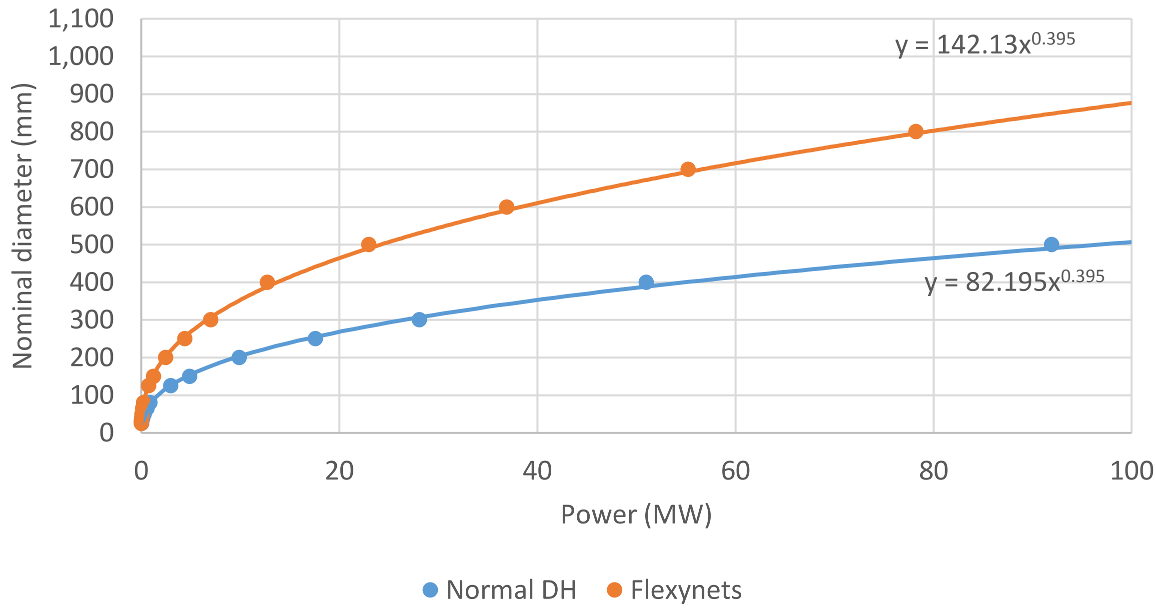


Figure 30 – The required nominal diameter for district heating transmission pipes as a function of the transmitted energy flow, for conventional pumping velocities. The data used in the figure is the same as used in the Task 3.1 report in the FLEXYNETS project. The data sets have been fitted with power curves, which show a very good correlation with the data.

By combining the data from Figure 29 and Figure 30, an expression for the piping costs as a function of the energy flow can be obtained. As shown in Figure 29, the piping costs c as a function of the nominal pipe diameter can be expressed as a 2nd order polynomial:

$$c(d) = \alpha d^2 + \beta d + \gamma \qquad \text{(Equation 6)}$$

Here d is the nominal pipe diameter and α, β and γ are constants. As shown in Figure 30, the nominal diameter can be expressed as a function of the heating power in the form of a power law:

$$d(Q) = aQ^b \qquad \text{(Equation 7)}$$

Here Q is the power and a and b are constants. By inserting Equation 7 in Equation 6, the following expression for the piping costs as a function of the heating power can be obtained:

$$c(Q) = \alpha a^2 Q^{2b} + \beta a Q^b + \gamma \qquad \text{(Equation 8)}$$

Figure 31 shows plots of Equation 8 for the case of normal DH networks and for the FLEXYNETS concept. The assumed values for the constants α, β, γ, a and b are those from the fits in Figures 29 and 30.

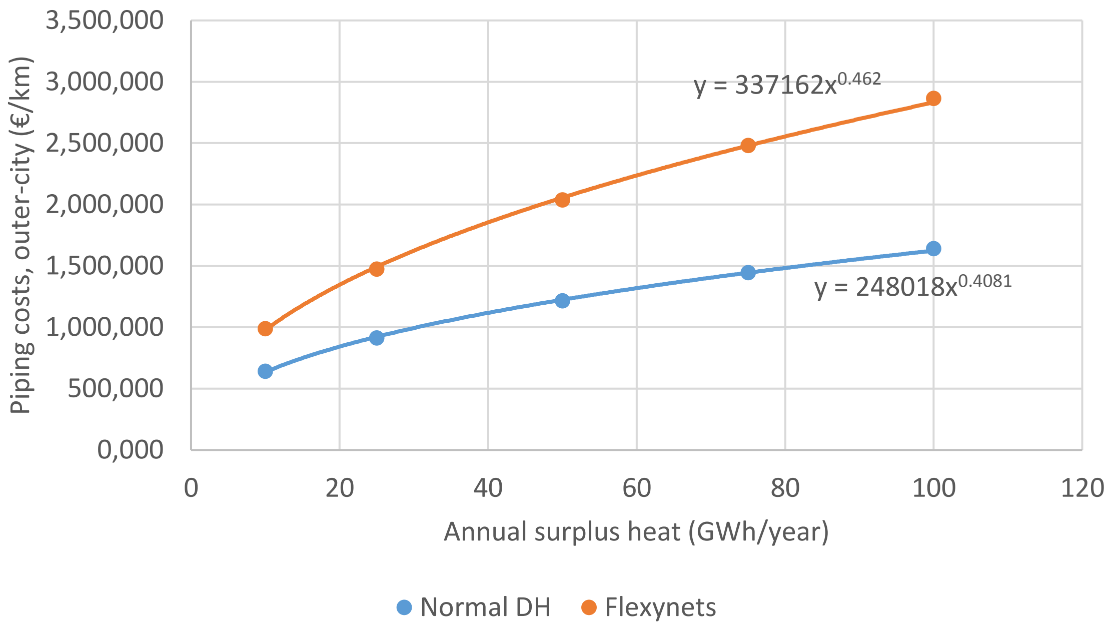


Figure 31 – The length-specific district heating piping costs for outer-city areas shown as a function of the annually transmitted surplus heat. Here it is assumed that the surplus heat is transmitted continuously with a constant power (constant temperature and flow rate) throughout the year.

Defining $E = \sum_{year}(Q)$, the length-specific, annualized investment costs for the transmission piping is:

$$c_{annual}(E) = \frac{r\, c(E)}{1-(1+r)^{-n}} \qquad \text{(Equation 9)}$$

Here r denotes the interest rate and n is the lifetime of the pipes in years (as well as the payback period).

4.2 Pipeline distance and heat price

Let us assume that the heat price is composed of three factors; the unit heat price in the existing district heating network without surplus heat utilization (p_{netw}), the unit heat price for the surplus heat (p_{exc}) and the annualized transmission pipeline investment costs for transmitting the surplus heat to the storage. The total unit heat price in the network p_{total}, including the surplus heat transmission and utilization, can then be expressed as a function of the pipeline length x:

$$p_{total}(x) = p_{netw}(1 - s) + p_{exc}s + c_{annual}(sE_{tot})x \qquad \text{(Equation 10)}$$

The parameter s is defined to denote the fraction of the total network heat demand that is supplied with the surplus heat. If s = 1, all heating demand in the network (on an annual basis) is supplied by surplus heat and if s = 0, none of the heat in the network is supplied with the surplus heat. If E_{tot} is the total heat demand in the district heating network, sE_{tot} is then the annual amount of surplus heat transmitted through the pipeline. $c_{annual}(sE_{tot})$ is then the length-specific piping cost from Equation 9, with $E = sE_{tot}$.

By making some assumptions about the parameters in Equations 8 - 10, it is possible to make a numeric estimate of how the possible surplus heat utilization (including transmission) would affect the heat price in the network. It is also possible to get an indication of the maximum distance over which it could be feasible to transfer surplus heat to the network. Let us assume that the annual heat demand in the network is 100 GWh/year. For comparison, the annual heat demand in the Danish city of Sønderborg, with around 30,000 inhabitants, is approximately 370 GWh/year. It is assumed here that the average heat price in the network, without the surplus heat supply, is 50 €/MWh corresponding to an approximate cost of natural gas based boiler heat incl. taxes. The assumed price of the surplus heat, excluding transmission costs, is assumed to be 0 €/MWh here. This is intended to reflect the assumption that the surplus heat is energy that otherwise would go to waste. The lifetime of the district heating pipeline is assumed to be 25 years and the interest rate on the investment is assumed to be 3%.

The heat price in the district heating network according to Equation 10, using the assumptions from the previous paragraph, is plotted in Figure 32 for five different values of s. Nothing has been assumed about the hourly or seasonal distribution of the heat demand in this simplified analysis. A constant in-flow of surplus heat to some type of a heat storage that can be utilized to fully balance the surplus heat supply and heat demand in the network has implicitly been assumed. The costs of the heat storage are not included in the analysis. The analysis also does not include any heat losses during transmission or storage. Due to these simplifications, the results in Figure 32 should be interpreted as "ideal-world", upper bounds on how far it can be beneficial to source surplus heat to the district heating network.

Here the values for conventional, high temperature district heating pipelines are used, as it is assumed that the surplus heat is transmitted at the source temperature, and not at the FLEXYNETS operating temperature. The black, dashed line in the figure shows the case of s = 0, i.e. when no surplus heat utilization takes place and $p_{total} = p_{netw}$. This indicates an example of the cost of alternative heat supply. The intersection of the black, dashed line and the remaining lines in the figure (for each value of s) shows for which pipeline length the total heat price (including the surplus heat utilization) equals the alternative heat price in the network (i.e. the price without the surplus heat utilization). For a given distance, if the heat price *with* the surplus heat is higher than the heat price *without* the surplus heat, it is not economically feasible to transmit and utilize the surplus heat, because it can be provided cheaper by other means. This gives an estimate of how long the heat transmission pipeline can be, before becoming too expensive.

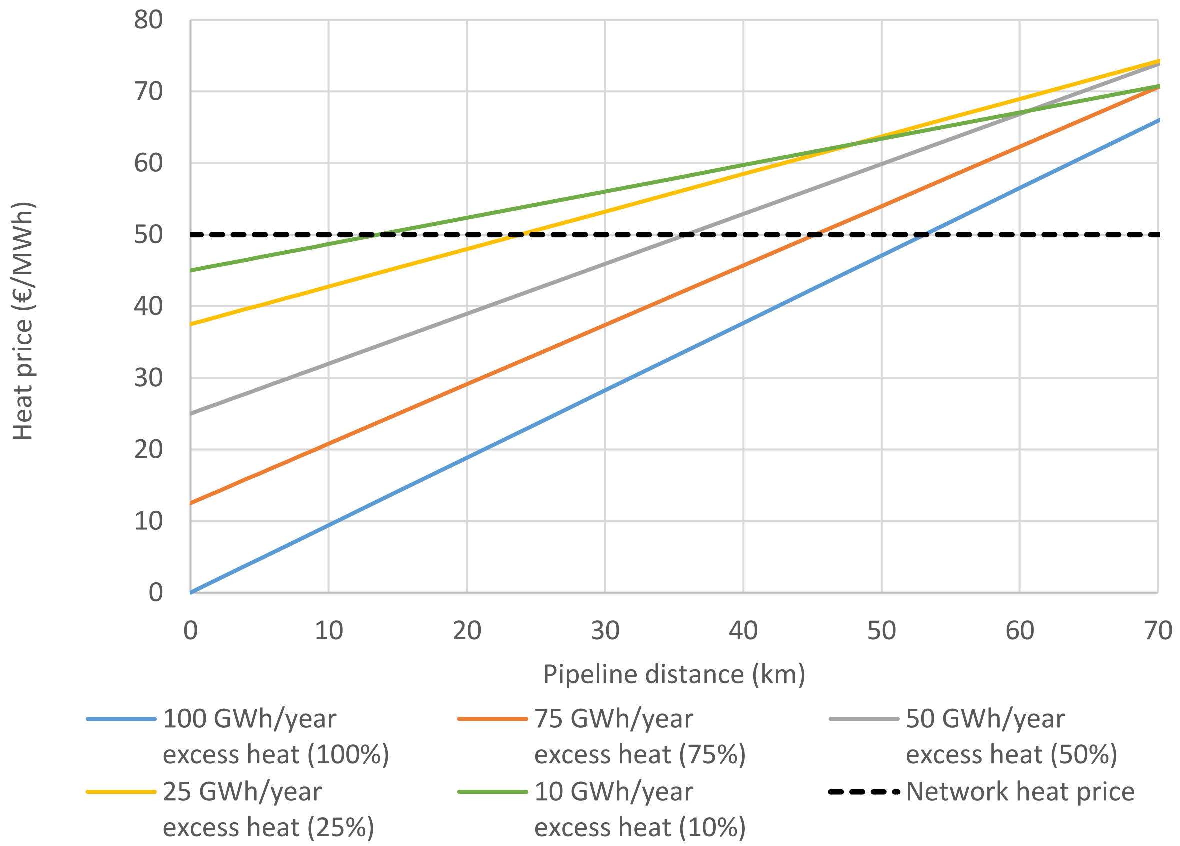


Figure 32 – The heat price in the district heating network shown as a function of the surplus heat transmission pipeline distance. This calculation is for the case of normal district heating temperatures. The price is shown for five different levels of surplus heat supply to the network. The calculation is done on an annual basis, not taking hourly and seasonal fluctuations in surplus heat supply and heat demand in the network into account, and without assuming any costs for thermal energy storage.

As can be seen in the examples of Figure 32, the limit to the feasible pipeline distance is highly dependent on the heat quantities and ranges. For the chosen parameters, the feasible distance limit ranges from approx. 12 km for the transmission of 10 GWh/year (s = 0.1) to over 50 km for the transmission of 100 GWh/year (s = 1).

These numbers should, however, only be interpreted as rough estimates, as they depend on a number of assumptions and choice of parameters. The specific construction costs of the heat transmission pipeline may also vary quite a lot depending on which type of area it is constructed through (urban, suburban, rural). The answer to the question of how far it is feasible to fetch surplus heat is therefore very dependent on the case at hand, but it is also very clear that the answer depends highly on how much surplus heat is available compared to the total heat demand in the network.

A more detailed analysis of centralized storages in the FLEXYNETS concept, including the transmission and utilization of high-temperature surplus heat, is presented in the next chapter. This analysis gives a more detailed answer to the question of how far away from the network it could be economical to source surplus heat. Here, the differences in supply and demand profiles, and transmission pipelines energy losses are taken into account.

5 TRNSYS Simulations

The aim of this report, as already mentioned, is to provide answers to the question if and in what contexts large-scale thermal storages could be beneficial for the FLEXYNETS concept. In chapters 2 and 3, the principles, technical properties and economic aspects of latent thermal energy storage have been assessed in the context of FLEXYNETS. In chapter 4 the possibilities regarding surplus heat transmission from heat sources away from the FLEXYNETS network have been addressed. In order to put these pieces together and to try to provide a more detailed answer regarding the role of large thermal storages in the FLEXYNETS concept, a model have been developed in the simulation environment *TRNSYS.* This model has been used for analysing thermal storages (tank, pit, borehole and aquifer storages) and surplus heat utilisation in a FLEXYNETS context for various scenarios, with different geographical locations, storage types, storage sizes, operating temperatures and amounts of surplus heat availability.

A focus has been on the circumstances under which large thermal storages is believed to have the opportunity to play the most important role and be most economical in the FLEXYNETS concept. These circumstances are when surplus heat from e.g. industry is available and is transmitted directly to a thermal storage at a temperature higher than the FLEXYNETS network temperature. Storing at a high temperature enables the storage to work with a greater ΔT than if the heat were stored at the network temperature, thus increasing the volumetric energy storage density and decreasing the energy-specific storage investment costs. The idea is then that the heating and cooling demands in the network are fulfilled to the highest possible extent by utilizing the surplus heat and the thermal contents in the storage even though the demand profiles are most likely very different from surplus heat input profile. For satisfying heating and cooling demand not provided by the surplus heat and the storages, the modelled system has centralized boiler and chiller units. The objective is, however, to operate the boiler and chiller units as little as possible. In this way, the system strives to replace as much of its fuel and/or electricity consumption for heating and cooling with surplus heat that would otherwise go to waste, and thereby also reduce the CO_2 emissions arising from the boiler and chiller operation.

For comparison, scenarios with conventional district heating temperatures and scenarios where the surplus heat is transmitted and stored at the FLEXYNETS forward temperature have also been included. Calculations for various transmission pipeline distances, including scenarios where no transmission pipeline is assumed to be necessary (when the surplus heat is located within the FLEXYNETS network area) have also been carried out. To evaluate the results in each scenario, two indicators are used: The thermal energy production costs (in units of €/MWh) in the network, and the annual CO_2 emissions arising from the boiler and chiller operation (in units of ton/year).

5.1 System description and TRNSYS model layout

5.1.1 System principle diagram

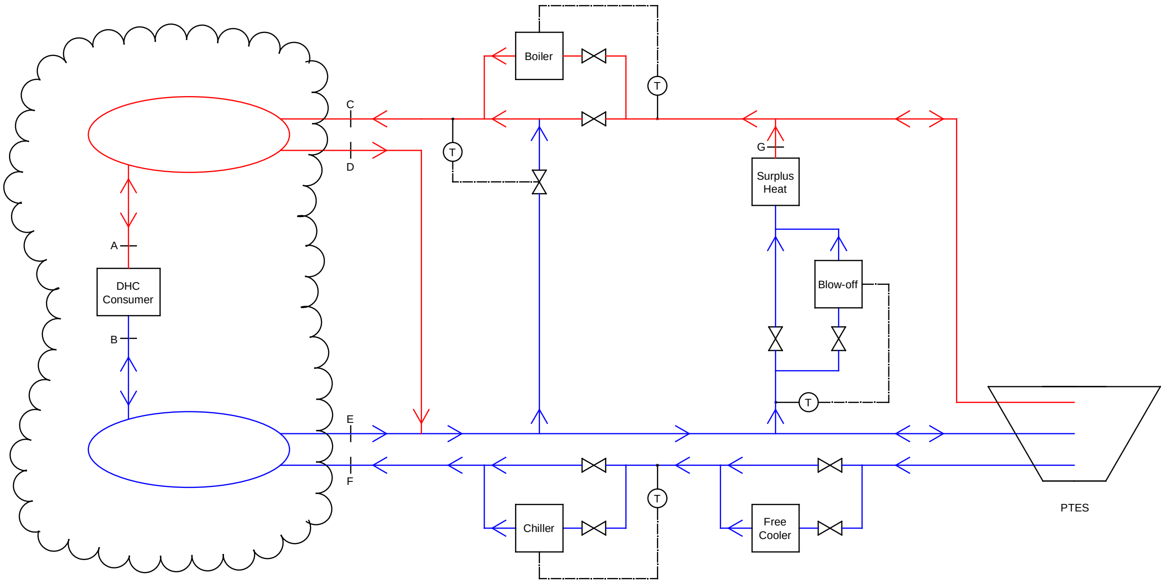
Two principle diagrams of the system outlined in the last paragraphs are shown in Figure 33. The two diagrams are identical, except for the thermal energy storages on the right-hand side of the figures. The diagrams show how the system with surplus heat input, a thermal storage, a boiler and a cooler is assumed to interact with the FLEXYNETS network. The FLEXYNETS network is pictured as two rings (one warm and one cold) and a cloud of consumers on the left-hand side of the diagrams. For illustration, the connections of a single consumer are shown in the diagram (markers A and B). When the consumer demands heating, there is a flow from the warm ring to the cold ring, with the consumer extracting heat from this flow. When the consumer demands cooling, these flows switch direction. In cooling mode, the consumer thus injects heat to the network.

Surplus heat is injected into the system (at marker G), and depending on the heat demand in the given hour, the heat flows either into the storage or directly to the network (via marker C). On the way to the warm ring, a shunt mixes colder water (flowing from marker E) with the inlet heat flow for adjusting the inlet temperature to the warm ring, if needed. In times of heating demand, the return flow from the consumer is stored as cold (flowing via marker E) in the lower part of the stratified TTES or PTES, or in the cold wells of the ATES or BTES. In times of cooling demand, cold is extracted from the storage and injected to the cold ring (via marker F). The warmer return water may be returned to the thermal storage (via marker D).

To ensure that the warm ring temperature is always sufficiently high, a boiler injects heat into the system (before marker C) in case the forward temperature to the warm ring is below the required warm ring temperature. To ensure that the cold ring temperature is always sufficiently low, a free cooler can be used to reduce the forward temperature to the cold ring down to the current ambient temperature, and a chiller (heat pump) can be used to further reduce the forward temperature (before marker F), if needed. As already mentioned, the system strives to operate the boiler and coolers as little as possible, as their operation leads to natural gas consumption and CO_2 emissions that can be avoided/reduced by fully/partly fulfilling the heating and cooling demand by using the surplus heat and the storages.

The system in Figure 33 exists in four variations; one for each type of thermal energy storage. The TTES is connected directly to the system. It is assumed to be a stratified hot water storage with inlets and outlets at the top, in the middle and at the bottom (for hot, lukewarm and cold water respectively). The PTES is connected to the system via heat exchangers and is also assumed to be a stratified hot water storage with top, middle and bottom inlets and outlets. In the case of the ATES or BTES storage, a buffer tank (a relatively small TTES) is connected to the system, and the ATES or BTES connects to the buffer tank. This is because the properties of ATES and BTES do not allow for very fast heat injection or extraction. It is therefore beneficial to have relatively small TTES to handle short-term differences between thermal energy supply and demand, and to use the ATES or BTES to handle seasonal variations in the supply and demand. The ATES and BTES are not stratified, but instead have separate warm wells and cold wells for storing heat and cold. The ATES is connected via heat exchangers, but the BTES is connected directly to the buffer tank.

a)



b)

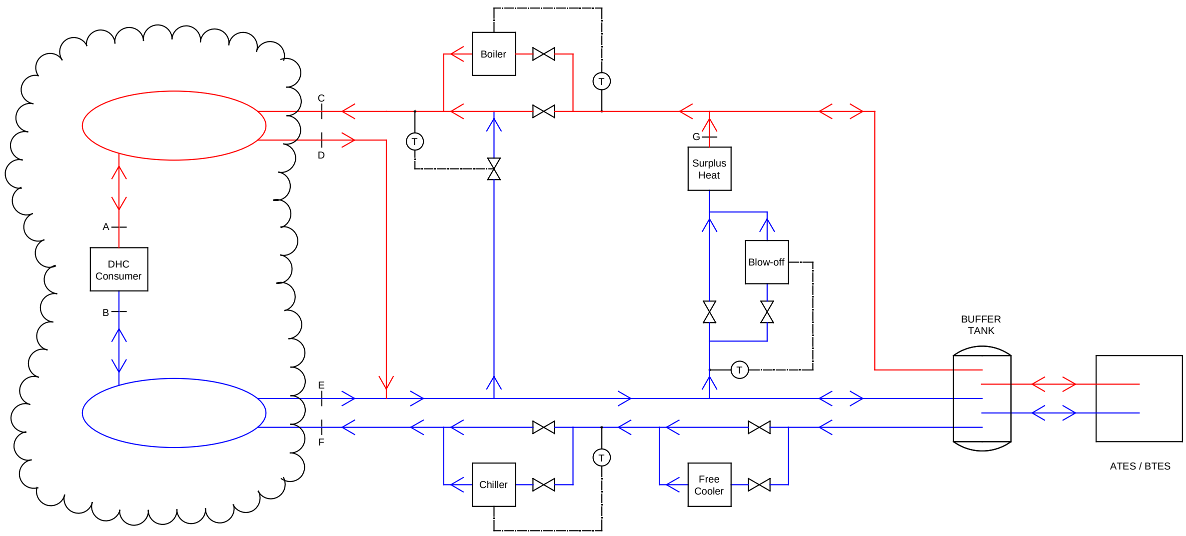


Figure 33 - Principle diagrams of the system. a) With either a tank storage or a pit storage. b) with either an aquifer storage or a borehole storage.

5.1.2 TRNSYS model layout

A screenshot of the *TRNSYS* model layout is shown in Figure 34. The layout of the model differs somewhat from the layout shown in the principle diagrams in Figure 33 due to practical modelling limitations, but the *TRNSYS* model can be considered a good approximation of the system in the principle diagrams. The red lines denote warm streams, the blue lines denote cold streams and the pink lines denote streams with lukewarm (warmer than the coldest streams but colder than the warmest streams) or highly varying temperatures. As can be seen in the model layout, all four thermal energy storage technologies have been modelled in a single *TRNSYS* model. It is, however, only possible to use one of the four thermal energy storage types during each model run, and this must be done before the model run.

All storage types are connected to a surplus heat input loop, a heating demand loop and a cooling demand loop. The surplus heat loop contains a pump that uses electrical energy for pumping the surplus heat from the source to the storage. As in the principle diagram, the heating demand loop contains a peak load boiler for raising the temperature and a shunt for lowering the temperature, to ensure that the heating demand receives water at the correct temperature. Similarly, the cooling demand loop contains a free cooler and a chiller (heat pump) for lowering the temperature in order to ensure that the cooling demand receives water at the correct temperature.

In the model runs with conventional DH temperatures (i.e. 80 °C forward temperature, 40 °C return temperature and a surplus heat inflow of 80 °C), a single system for providing district heating and cooling (DHC) is no longer energy-efficient in this model setup. This is because in the model, it does not make sense to cool the 40 °C warm heating return water down to the required 15 °C inlet temperature of the cooling demand and then heat the same water up again (to 80 °C) when it exits the cooling consumers at 20 °C. The combined DHC network can make sense when the temperature of the heating and cooling supply are closer together. For these model runs, it was found more beneficial to remove the connection between the cooling loop and the rest of the model. For the scenarios with conventional DH temperatures, the model therefore functions as two separate systems for district heating (with an inflow of surplus heat) and district cooling (with a free cooler and a chiller heat pump).

The storages are connected as described above, with the PTES and ATES having heat exchangers and with ATES and BTES having small buffer TTES for balancing short term fluctuations between thermal energy supply and demand. The following *TRNSYS* types are used for modelling the heat storages: Type 4a (TTES and buffer tanks), Type 342 (PTES), Type 345 (ATES) and Type 557b + Type 3001 (BTES). These *TRNSYS* components aim to simulate the physical characteristics of each storage type and include detailed parameters for the size and shape of the storages and for the calculation of energy losses through the lid and the sides. For ATES and BTES, the components furthermore include various parameters describing the thickness, initial temperature, heat capacities, thermal conductivities etc. for the underground.

The economic part of the *TRNSYS* model, with black lines, can be seen in the lower right part of Figure 34. Here the annual investment costs, operation & maintenance costs, energy input costs for the boiler, chiller and pumps and the CO_2 amounts and costs for the model are calculated. This is used for calculating the generation price for the thermal energy (heating and cooling) and the annual CO_2 emissions arising from operating the boiler and coolers. These two parameters are used as indicators for the performance of the different model scenarios, as better described in section 5.4.

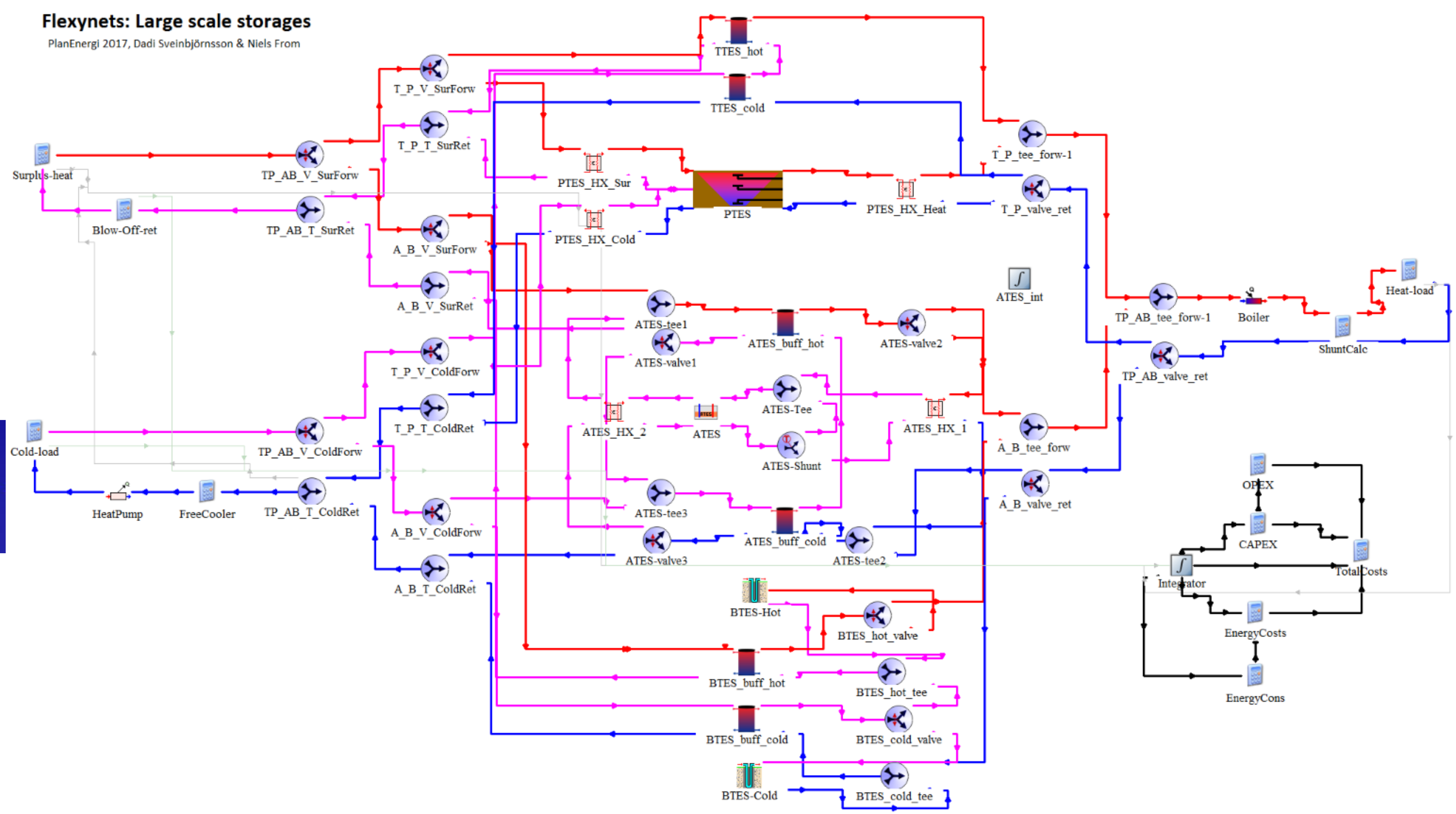


Figure 34 – The layout of the TRNSYS model. All four thermal storage technologies have been modelled in a single TRNSYS model. Prior to each model run, the modeller chooses which storage will be used, and it is only possible to use one storage type in each model run (TTES, PTES; BTES or ATES).

The FLEXYNETS network, the heat storages and the surplus heat sources have been modelled in *TRNSYS* using an aggregated, top-down approach. The model only includes a single surplus heat source, a single thermal energy storage (which has an extremely large volume compared to the demand in some scenarios), a single heat demand and a single cooling demand. In reality, there would most likely be multiple instances of most of these system components; i.e. there could be multiple surplus heat sources, multiple thermal energy storages (rather than one large) and thousands of consumers with a heating and a cooling demand. However, from the storage's point of view, the connection to the network will in practice correspond to an aggregated demand profile.

The *TRNSYS* simulation software was set to calculate the mass flows and temperatures in the modelled energy system (including thermal energy storages) in 1-hour time steps. In all simulations carried out in this work, the length of the simulation period has been set to two years, or 17,520 time steps, and all results shown here are for the 2nd simulation year. This is because the initial values of some simulation parameters, such as the thermal energy storage state of charge, are not known at the beginning of a simulation. Using results from the 2nd simulation year, when the storages have already been simulated for one year, is therefore more accurate.

5.2 Model inputs and assumptions

The technical model input data is shown in Table 5.1 and the economic model input data is shown in Table 5.2. Further explanation of the values in the tables is given in the notes after each table.

Table 5.1 – Model input data regarding CO_2 emissions, efficiencies and energy losses.

Technical model input data	**Value**	**Unit**	**Note**
CO_2 emissions			
CO_2 emissions pr. surplus heat energy input	0	t/MWh	A
CO_2 emissions pr. boiler energy input	0.205	t/MWh	B
CO_2 emissions pr. electrical energy input	0.202	t/MWh	C
Boiler and cooler efficiencies			
Boiler efficiency	100	%	D
Free cooler COP	50	-	E
Chiller (heat pump) COP	7.5	-	F
Other energy losses			
Heat exchanger effectiveness	90	%	G
Transmission pipeline temperature loss	0.25	K/km	H
Electricity consumption for pumping surplus heat	2	% of surplus heat in	I

Notes to Table 5.1:

A. The companies that produce the surplus heat as a part of their activities are assumed to be responsible for the associated CO_2 emissions. These emissions would take place regardless of whether the surplus heat from the process is utilized or not.
B. The peak load boiler in the model is assumed to be a gas boiler. This number is the energy-specific CO_2 emissions value for natural gas combustion, published by the Danish Energy Agency. The emissions from natural gas can be different in other areas based on the origin of the gas.
C. The free cooler, chiller (heat pump) and the pump for surplus heat supply are assumed to be electricity driven. For the energy-specific CO_2 emissions of the electricity consumption, the average CO_2 emissions value of Danish electricity consumption in 2015 is used (Energinet, 2016). The EU average for this is 0.377 t/MWh (IINAS, 2014), and this is expected to fall in the future as the share of renewables increases.
D. The gas boiler is assumed to be a modern condensing boiler with efficiency of 100%.
E. The free cooler is assumed to yield 50 units of cooling energy for each unit of electricity it consumes. This is a common COP for free coolers of the assumed type.
F. The chiller (heat pump) is assumed to yield 7.5 units of cooling energy for each unit of electricity it consumes. This is a calculated value for the average COP of a heat pump operating in the temperature range 10 - 20 °C.
G. All heat exchangers in the model are assumed to have 10% loss in temperature.
H. The temperature loss in the surplus heat transmission pipeline is assumed to be 0.25 K for each kilometre. This is realistic compared with losses of some of the longest heat transmission pipelines in the worlds located in Iceland.
I. The electrical power required to pump the surplus heat in the transmission pipeline is assumed to correspond to 2% of the thermal power provided by the surplus.

Table 5.2 – All model input data for the calculation of costs in the model.

Economic model input data	**Value**	**Unit**	**Note**
Energy price			
Surplus heat price	0	€/MWh	A
Peak load heating price (from boiler)	50	€/MWh	B
Electricity price	50	€/MWh	C
Investment costs			
TTES and buffer tanks	$5295 \cdot V^{-0.435}$	€/m³	D
PTES	$2267 \cdot V^{-0.374}$	€/m³	D
BTES	$16726 \cdot V^{-0.649}$	€/m³	D
ATES	$1467 \cdot V^{-0.098}$	€/m³	D
Transmission pipeline	$248018 \cdot Q^{0.408}$	€/km	E

Boiler	0	€/MW	F
Chiller	0	€/MW	F
Free-cooler	0	€/MW	F
Operating expenses			
TTES	2	% of inv.	G
PTES	2	% of inv.	G
BTES	2	% of inv.	G
ATES	2	% of inv.	G
Transmission pipeline	0	% of inv.	G
Economic calculation parameters			
CO_2 emission cost	28	€/ton	H
Investment lifetime	25	years	I
Interest rate	4	%	I
Price level	2017 prices		I

Notes to Table 5.2:

A. The surplus heat is assumed to be available from the source free of charge.

B. The price range for district heating from gas boilers in the analysis assumptions of the FLEXYNETS project is 40 – 55 €/MWh.

C. The assumed electricity price to the free cooler, chiller and the pump for the surplus heat. This is assumed to be the average electricity spot price, exempt from taxes and tariffs.

D. The volume-specific investment costs for the thermal storages are based on the fits for the cost curves for the storages presented in Chapter 3. *V* denotes the storage volume (water equivalent) in m^3. It is assumed that above a certain ”cut-off” volume, the economy of scale no longer apply, and the marginal investment costs continue as a constant number, rather than a volume-dependent cost curve. This ”cut-off” volume was set to 100,000 m^3 for TTES, 300,000 m^3 for PTES, 500,000 m^3 (water equivalent) for BTES and ATES.

E. The transmission pipeline costs are based on the piping costs in outer-city areas for normal district heating temperaturas (assuming a high temperature surplus heat), presented in Figure 31 in Chapter 4. *Q* denotes the annually transmitted heat (in GWh/year).

F. The investment costs and O&M (operation and maintenance) costs for the boiler are assumed to be included in the peak load heating price (see note B). The investment costs and O&M costs for the chiller and the pumps are not included in the model.

G. The O&M costs are calculated as a percentage of the total (non-annualized) investment costs. The O&M costs of the transmission pipeline are neglected.

H. The boiler and chiller are assumed to be centrally located in the network and thus be included in the ETS CO_2 quota trading system. The CO_2 cost value in the table corresponds to IEA's estimate for the price of CO_2 emission quotas in the year 2030. The 2030 price level was chosen because FLEXYNETS is still under development and is unlikely to be deployed on a large scale before 2030.

I. The investment lifetime and interest rate are used for calculating the annualized capital expenses (using the annuity loan down-payment formula). No inflation is included in the model. The model assumes a constant 2017 price level. A real interest rate of 4%, as recommended for socio-economic analysis by the Danish Energy Agency.

5.3 Scenarios description

A large number of scenarios have been modelled using the *TRNSYS* model. As already mentioned, the model has been run for four different types of storages (TTES, PTES, BTES and ATES). Each storage type has been run for seven different volumes (see Table 5.3). The model has furthermore been run with five different magnitudes of surplus heat availability (see Table 5.4). The surplus heat availability is also quantified in terms of the so called "surplus heat share", defined as the ratio between the total annual surplus heat supply and the total annual heating demand (without considering the time distributions of the supply and demand). The model has furthermore been run for five different sets of temperature levels (see Table 5.5). Finally, all these variations have been run for three different reference cities (Rome, London and Stuttgart, see section 5.5).

For investigating all these different combinations, a total of 2,100 model runs have been performed. Each model run took 30-60 seconds on a laptop computer, depending on which thermal storage type was being simulated. After defining the scenarios and setting up the model, the model runs were automated to a large extent using the "parametrics" function in the *TRNEDIT* software that is bundled with *TRNSYS*.

Table 5.3 – The range of thermal energy storage volumes used in the model runs. These should not be interpreted as the volumes of single, extremely large storages, but rather as aggregated volumes for multiple smaller storages. The volumes of ATES and BTES are given in water equivalents.

Storage volumes (m^3)	TTES	PTES	BTES (water eq.)	BTES buffer tank	ATES (water eq.)	ATES buffer tank
Volume 1	20,000	20,000	20,000	20,000	20,000	20,000
Volume 2	100,000	100,000	100,000	20,000	100,000	20,000
Volume 3	200,000	200,000	200,000	40,000	200,000	20,000
Volume 4	550,000	550,000	550,000	110,000	550,000	55,000
Volume 5	1,000,000	1,000,000	1,000,000	200,000	1,000,000	100,000
Volume 6	1,500,000	1,500,000	1,500,000	200,000	1,500,000	200,000
Volume 7	2,000,000	2,000,000	2,000,000	200,000	2,000,000	200,000

Table 5.4 - The five different variations in the amount of annual surplus heat supply to the system (column 2) as well as the assumed annual heating and cooling demand.

Surplus heat share (%)	**Surplus heat (GWh/year)**	**Heating demand (GWh/year)**	**Cooling demand Rome (GWh/year)**	**Cooling demand London (GWh/year)**	**Cooling demand Stuttgart (GWh/year)**
125%	125	100	25	7.5	10
100%	100	100	25	7.5	10
75%	75	100	25	7.5	10
50%	50	100	25	7.5	10
25%	25	100	25	7.5	10

Table 5.5 – The five different variations in the operating temperatures of the system.

Variation no.	**Description of variation**	**Surplus heat**	**Heating forward**	**Heating return**	**Cooling forward**	**Cooling return**
I.	Conventional DH, separate heating and cooling systems	80	80	40	15	20
II.	HT surplus heat, FLEXYNETS ΔT = 10	80	25	15	15	20
III.	Medium surplus heat, FLEXYNETS ΔT = 10	60	25	15	15	20
IV.	Medium surplus heat, FLEXYNETS ΔT = 15	60	25	10	10	20
V.	LT surplus heat, FLEXYNETS ΔT = 10	25	25	15	15	20

Table 5.4 shows the five different variations in the amount of annual surplus heat supply to the system (column 2). The assumed values for the annual heating demand and the annual cooling demand in each case are also shown. The cooling demand is assumed to differ between the three reference cities due to differences in climate. The first column in the table shows the "surplus heat share", which is defined as the ratio between the annual surplus heat supply and the annual heating demand. When the surplus heat share is 100%, the total annual surplus heat inflow to the system equals the total annual heating demand in the system (without any consideration of the time distribution of the supply and demand).

Table 5.5 shows the different variations in the operating temperatures of the system. Variation I corresponds to conventional district heating temperatures. Variation II assumes a FLEXYNETS system operating with forward and return temperatures of 25 °C and 15 °C and surplus heat available at 80 °C. Variation III assumes the same FLEXYNETS system, but with surplus heat available at 60 °C. Variation IV Considers a FLEXYNETS system with forward and return temperatures of 25 °C and 10 °C and surplus heat available at 60 °C. Variation V considers a FLEXYNETS with forward and return temperatures of

25 °C and 15 °C and surplus heat available at the network forward temperature, 25 °C. The return temperature from the cooling demand is in all cases assumed to be 20 °C (and not 25 °C, like the heating forward temperature), due to practical temperature limitations of commercially available heat pump technology.

5.4 Indicators

Two main indicators have been used for evaluating the outcome of the model scenarios:

1) The specific thermal energy production costs (the average costs of providing one MWh of heating or cooling during the year).
2) The annual CO_2 emissions arising from the operation of the boiler and coolers.

In the following, the calculation of the two indicators is described. Note that in the terminology used here, small letters are used to denote specific values (e.g. costs per volume, emissions per MWh, etc.) while capital letters are used to denote absolute vauuiulues (e.g. total costs per year, total emissions per year).

Indicator 1: Thermal energy production costs

The energy specific thermal energy production costs (c_Q, in unit of €/MWh) are calculated as the total annual costs (C) of the system (investment costs, O&M costs, external energy input costs and CO_2 emission costs) divided by the total heating and cooling energy (Q) provided during the year:

$$c_Q = \frac{C_{Inv,annualized} + C_{O\&M} + C_Q + C_{CO2}}{Q_{Heating} + Q_{Cooling}}$$

(Equation 11)

(Indicator 1)

In this equation, the annualized investment costs are defined as:

$$C_{Inv,annualized} = \frac{r \cdot (C_{Inv,transmission} + C_{Inv,storage})}{1-(1+r)^{-n}}$$

(Equation 12)

Where $C_{Inv,transmission}$ and $C_{Inv,storage}$ and denote the total investment costs of the transmission pipeline and the storage in the current scenario. Note that for ATES and BTES, the storage investment costs are the sum of the ATES or BTES investment and the investment in the associated TTES buffer respectively. The interest rate is denoted with r and the investment lifetime in years is denoted with n. The operation and maintenance costs ($C_{O\&M}$) in Equation 11 are calculated as a percentage of the total investment in transmission and storage, according to the values in Table 5.2.

The Total annual costs of external energy inputs to the system is:

$$C_Q = Q_{Boiler} \cdot c_{heating} + (E_{FreeCooler} + E_{HeatPump} + E_{Pumps}) \cdot c_{electricity} + Q_{surplus} \cdot c_{surplus}$$

(Equation 13)

Here Q denotes thermal energy, E denotes electrical energy and c denotes the cost of energy per MWh. A shown in in Table 5.2, $c_{surplus}$ is assumed to equal zero in all cases (the surplus heat is assumed to be available free of charge).

The total annual costs of CO_2 emissions from the operation of the boiler and the coolers is:

$$C_{CO2} = M_{CO2} \cdot c_{CO2} \qquad \text{(Equation 14)}$$

Here M_{CO2} are the annual CO_2 emissions from the boiler and cooler operation (indicator 2, shown in Equation 15) and c_{CO2} denotes the costs of emitting one ton of CO_2 (shown in in Table 5.2).

Indicator 2: Annual CO_2 emissions from heating and cooling

The total annual CO_2 emissions (M_{CO2}) from the boiler and cooler operation is:

$$M_{CO2} = Q_{Boiler} \cdot m_{CO2,Boiler} + (E_{FreeCooler} + E_{HeatPump}) \cdot m_{CO2,Electricity} \qquad \text{(Equation 15) (Indicator 2)}$$

Here Q denotes the annual fuel consumption of the boiler, E denotes the annual electricity consumption of the free cooler or the heat pump and m denotes the CO_2 emissions per MWh of boiler/cooler energy consumption.

5.5 Reference cities

Three reference cities were chosen as case studies for the model; Rome (IT), London (GB) and Stuttgart (DE). These cities were chosen for consistency with other parts of the FLEXYNETS projects. The hourly time series for the heating and cooling demand were constructed using a method based on statistics on the ambient temperature and based on assumptions about the set point temperatures for the heating and cooling demand. A part of the heating and cooling demand was in each case assumed to be constant throughout the year, independent of the ambient temperature. The resulting profiles for the heating and cooling demands are shown in Figures 35, 36 and 37 for the cases of Rome, London and Stuttgart.

The ambient temperature profiles used in the *TRNSYS* model and for the construction of the heating and cooling demand profiles were obtained from Meteonorm TMY2 data files, which represent the temperatures in an average year at the given location. An Excel-routine was used to calculate the heating demand during each hour of the year, by counting the number of ”degree-hours” (equivalent to degree-days, but on an hourly basis). The heating degree hours are counted as the difference between the heating set point temperature and the ambient temperature in each hour of the year. Each degree hour translates to a certain heating energy demand, and consequently hours with a very low temperature (a large difference between the heating set point temperature and the ambient temperature) translate to a high heating energy demand. The heating demand profile is constructed by repeating this for every hour of the year. The cooling demand profiles were constructed in an analogous way, with cooling degree hours counted as the difference between the ambient temperature and the heating set point temperature. In reality the cooling demand in residential and commercial buildings is also determined be the incident solar irradiance, but for the purpose of this analysis, an estimate based on ambient temperatures was considered sufficiently representative.

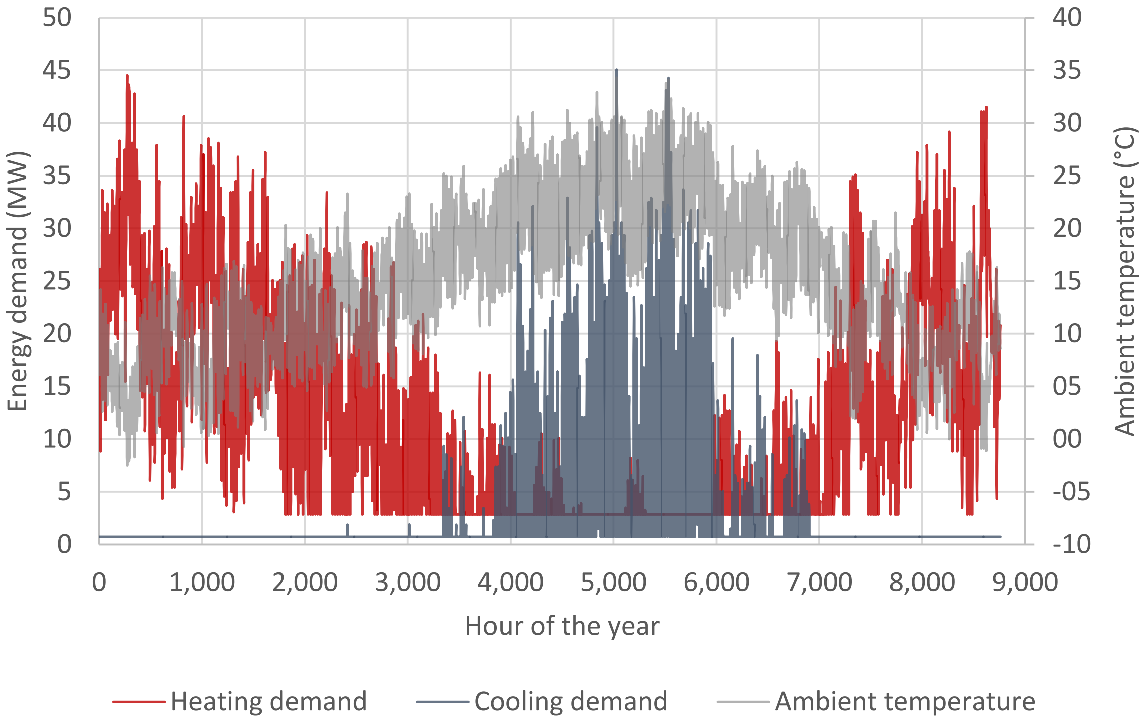


Figure 35 – The time-series for the ambient temperature, the heating demand and the cooling demand used for modelling the case of Rome.

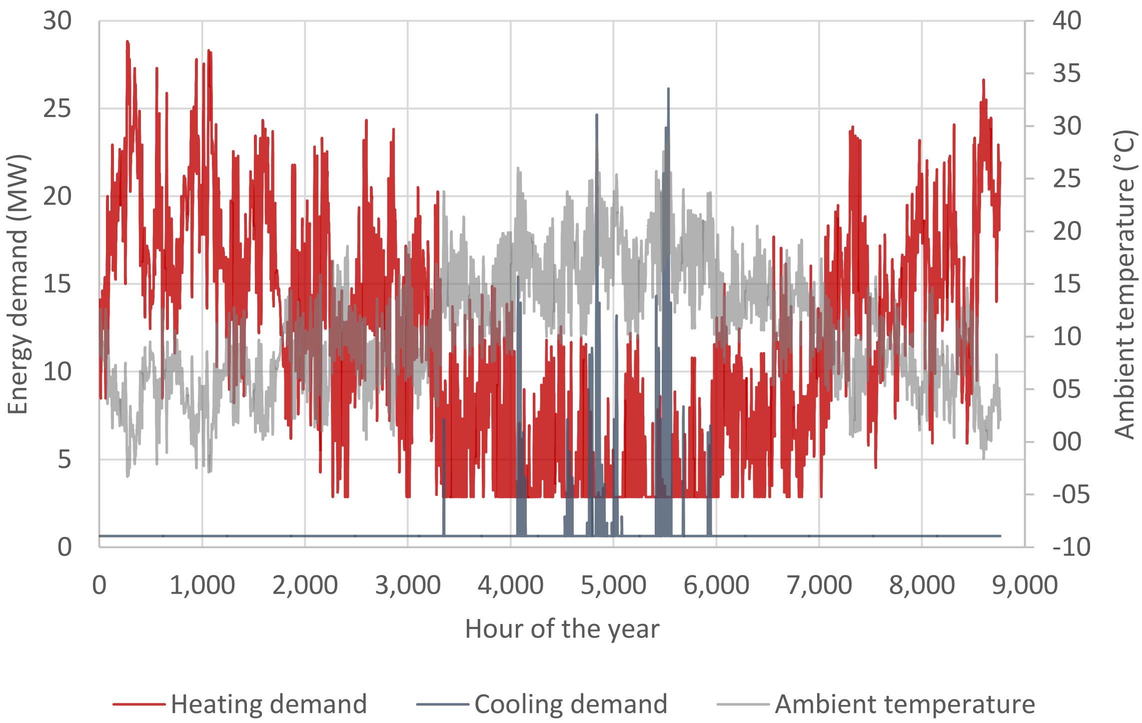


Figure 36 – The time-series for the ambient temperature, the heating demand and the cooling demand used for modelling the case of London.

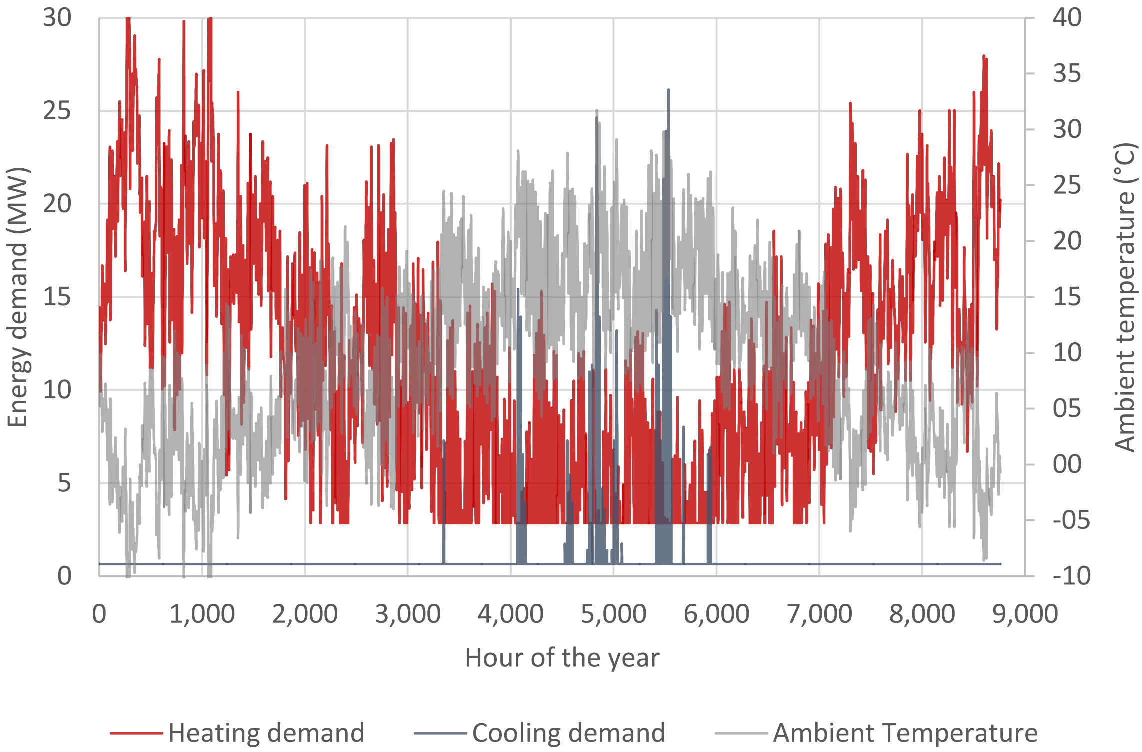


Figure 37 – The time-series for the ambient temperature, the heating demand and the cooling demand used for modelling the case of Stuttgart.

The heating set point temperature was assumed to be 17 °C for all three locations. The cooling set point temperature was assumed to be 23 °C for Rome and 22 °C for London and Stuttgart, due to possible differences in comfort requirements between Southern Europe and Mid-Europe. The ambient-temperature independent share in the heating demand was assumed to be 25% in all locations. This corresponds to hot water for other purposes than space heating, such as for bathing. The ambient-temperature independent share in the cooling demand was assumed to be 25% for Rome, 75% for London and 60% for Stuttgart. This was intended to reflect the fact that the need for space cooling is highest in Rome, and that a large share of the cooling demand in London and Stuttgart is not needed for space cooling that directly relates to the ambient temperature, but rather for cooling of supermarkets and large buildings (e.g. large office complexes, airports) that have some cooling demand all year round.

In this modelling, it was not the intention to model the total heating and cooling demand in each of the reference cities. The model is rather intended to represent a district or a neighbourhood within each of the cities; this could e.g. be a new development area in the city, where the FLEXYNETS concept would be implemented. Therefore, the same heating demand, 100 GWh/year, has been assumed regardless of the size of the reference city. To give an idea of the scale of the heating demand of 100 GWh/year, this can be compared to the heating demand of the Danish municipality of Sønderborg (population 27,000), which is approx. 370 GWh/year. In Danish climate, the heating demand modelled in the *TRNSYS* model can therefore be thought of as the demand of a district of approximately 7,500 inhabitants. The annual heating demand per person in London, Stuttgart and Rome is lower than in Denmark, and 100 GWh heat per year can therefore supply a somewhat larger population in those cities than in Denmark.

5.6 TRNSYS model results

5.6.1 Model dynamics and energy balance in the storages

The *TRNSYS* model calculates, among other things, the temperatures in the thermal storages, the energy injection and extraction to and from the storages and the storage state of charge for each time step (hour) of the simulation period. The model furthermore calculates the required heating power (from the boiler) and cooling power (from the free cooler and the heat pump) for each time step, based on surplus heat supply, the heating demand, the cooling demand and the storage injection and extraction in that time step. In the following, some examples of the results of a PTES model run for Rome are shown for one simulation year, in order to illustrate the dynamics of the model system.

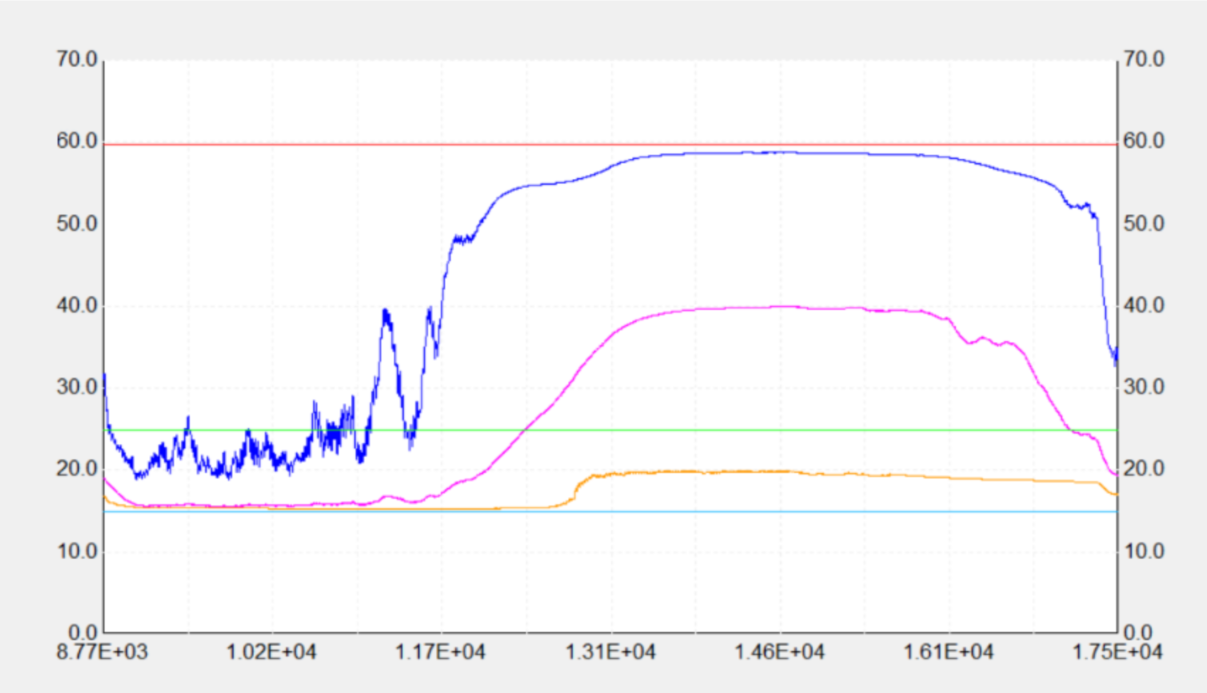


Figure 38 – An example of the development of the temperatures in the pit storage throughout the course of one simulation year in time steps of one hour. This example is for the case of Rome, a PTES storage of 500,000 m³, a 100% surplus share, 60 °C surplus heat temperature (red line), 25 °C forward temperature (green line) and 15 °C return temperature (cyan line). The dark blue and yellow line shows the temperature at the top and bottom of the PTES respectively. The pink line shows the average PTES temperature.

Figure 38 shows an example of the temperature development in the PTES storage during a single model run. The temperature is measured in a number of different heights in the storage; the figure shows the temperature at the top and the bottom of the storage as well as the averages temperature in the PTES.

Figure 39 shows the energy injection and extraction to and from the PTES for the same model run, as well as the PTES state of charge. The state of charge is defined as the current energy contents of the storage divided by the theoretical maximal energy contents of the storage (i.e. if all water in the storage were at the maximum storage temperature). The x-axis of the graphs covers one year, starting on January 1st (simulation hours 8,761-17,520, corresponding to the 2nd year of simulation). As can be seen in the figures, the storage is empty and cold after the winter, but is charged again during spring. In the summer, the storage has been charged to its maximum temperature. The storage remains at the maximum temperature until the autumn, where it is slowly discharged and eventually emptied during the winter. This development is as expected. The same kind of analysis was also performed for the other storage types.

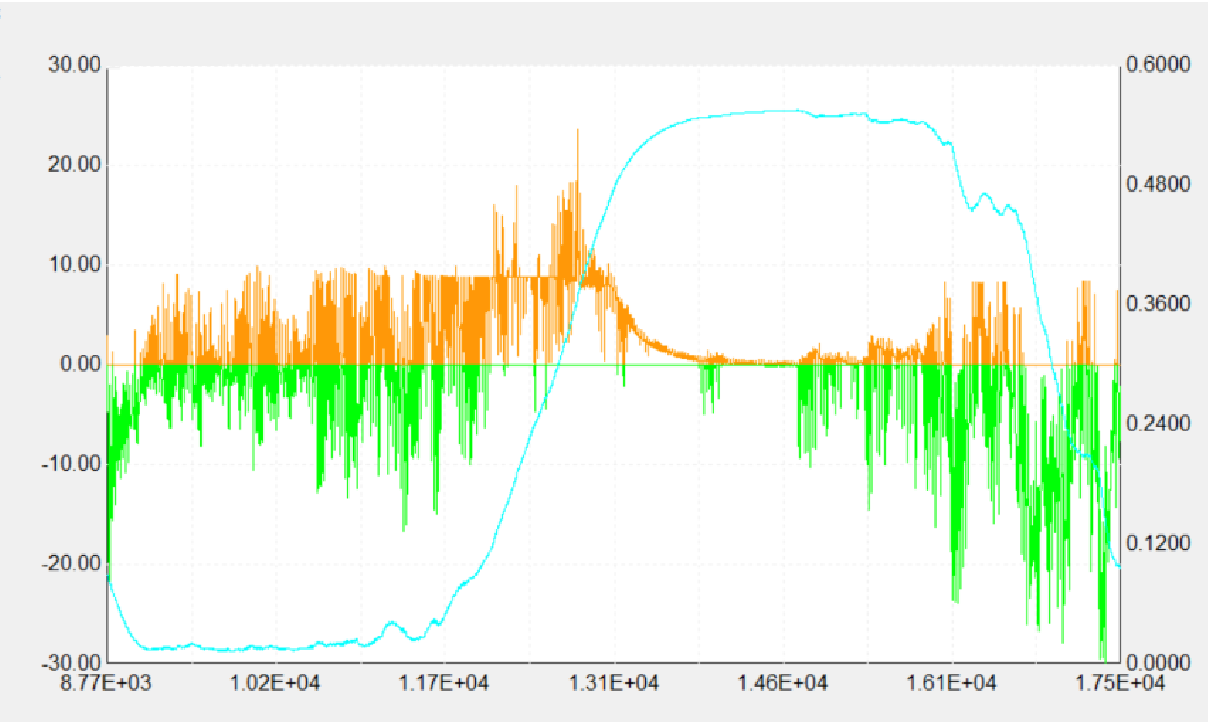


Figure 39 – An example of the PTES energy input (positive, yellow line) and output (negative, green line) as well as its state of charge (cyan line) throughout the course of one simulation year. The left secondary axis shows the energy input or output in MW and the right secondary axis shows the state of charge (as a fraction of a perfectly charged storage). This example is for the case of Rome, a PTES storage of 500,000 m³, a 100% surplus share, 60 °C surplus heat temperature, 25 °C forward temperature and 15 °C return temperature.

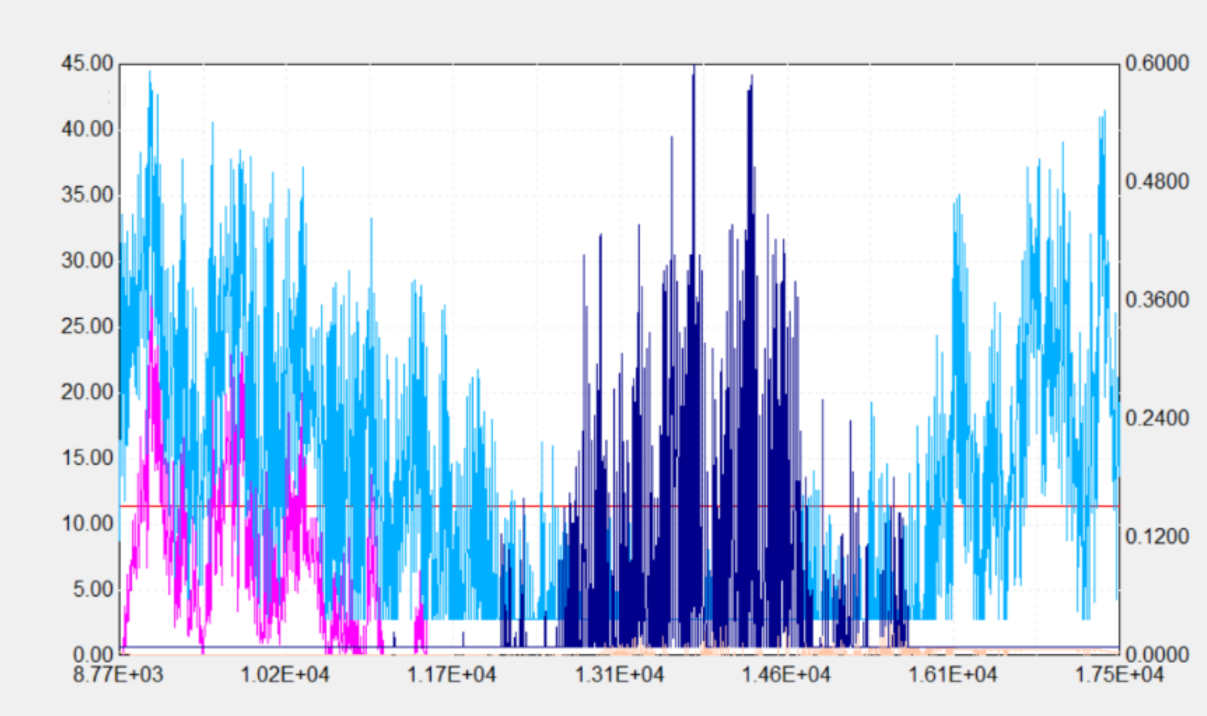


Figure 40 – The energy flows in the system during one simulation year: Surplus heat inflow (red line), heating demand (light blue line), cooling demand (dark blue line), boiler energy input (pink line) and chiller energy input (peach line). This example is for the case of Rome, a PTES storage of 500,000 m^3, a 100% surplus share, 60 °C surplus heat temperature, 25 °C forward temperature and 15 °C return temperature.

Figure 40 shows the energy flows (surplus heat inflow, heating demand, cooling demand, boiler energy input and chiller energy input) in the system during one simulation year, for the same PTES model run as discussed above. As can be seen, the boiler operates quite a lot during the first quarter of the year. This is because in this part of the year, the PTES is mostly empty. The boiler does, however, not operate during the last quarter of the year, even though there is a large heating demand. This is because the storage is full at the beginning of this quarter and can be used for fulfilling the required heating demand. Similarly, the coolers operate more in the late summer, because the bottom of the PTES is cold at the beginning of the summer but becomes warmer over the summer as the cold water is extracted to fulfil the cooling demand. It can be observed that the PTES is filled up long before the end of the summer period and is emptied long before the end of the winter. The graphs shown here therefore indicate that from a technical point of view, a larger PTES could benefit the system in this particular scenario by enabling more effective storage and usage of the surplus heat that is injected to the system, and thereby reducing the CO_2 emissions from boiler and cooler operation (indicator 2). This does, however, not provide any information about if a larger PTES would be feasible from an economic point of view (indicator 1). Also, an alternative control of the surplus heat injection to the network (i.e. restrictions during some periods) might improve the system as a whole due to a lower auxiliary cooling demand.

5.6.2 Reference case: Rome

In Figure 41 and Figure 42, results for the case of TTES in the reference city Rome are shown for the two indicators described in section 5.4 (thermal energy price and CO_2 emissions from heating and cooling).

Figure 41 shows the results for five different sets of operating temperatures, a constant "surplus share" of 100% (i.e. the annual surplus heat inflow equals 100% of the annual heating demand) and assuming no surplus heat transmission pipeline. It is clear from the figure that the lowest thermal energy price and the lowest CO_2 emissions are obtained when the surplus heat temperature is high and the forward and return temperatures are as low as possible. The scenarios with the conventional district heating temperatures performs worst on both indicators, followed by the scenarios with the surplus heat temperature equalling the FLEXYNETS forward temperature.

For the case of TTES in Rome, the lowest thermal energy price is obtained when no thermal storage is present. This may not be very surprising, since TTES are mostly not designed as seasonal storages in practice, but rather for balancing daily or perhaps weekly fluctuations in supply and demand. Investing in sufficient TTES capacity to store between summer and winter can therefore be expected to be expensive, compared to the other storage types (as seen in Figure 27). However, regarding CO_2 emissions, it is possible to obtain significant emission reductions by introducing TTES in the system (in case of FLEXYNETS operating temperatures and high surplus heat temperature). It should be noted that the heat price in the system without the surplus heat is assumed to be 50 €/MWh, and by introducing 1.5 - 2.0 million m^3 of TTES in the system, the CO_2 emissions from boiler and cooler operation can be lowered by more than 95% while still keeping the thermal energy price below 50 €/MWh.

In Figure 42, the results are shown for different amounts of surplus heat inflow to the system ("surplus share") for one sets of operating temperatures. As expected, the best results on both indicators are obtained for the highest amount of surplus heat inflow, as the surplus heat is assumed to be available free of charge and is not assumed to contribute to the system's CO_2 emissions. However, electricity demand for pumping, and the associated CO_2 emissions and costs are taken into account. Similar to the results in Figure 41, the thermal energy price increases when TTES is introduced, but the price level depends highly on the amount of surplus heat inflow. The CO_2 emissions from heating and cooling can in all cases be reduced by introducing TTES, but the magnitude of the CO_2 reduction is higher for large amounts of surplus heat inflow than for small amounts. This is because the storage capacity can be better utilized when there is a large inflow of heat to the storages.

The results for PTES for the case of Rome are shown in Figure 43 and Figure 44. Similar to the TTES case, the best performance on the two indicators is obtained for high surplus heat temperature and FLEXYNETS network temperatures. As shown in Figure 43, the lowest thermal energy price can be obtained by not investing in thermal storage. However, an investment in PTES capacity up to 1 million m^3 only leads to very minor increases in the thermal energy price (an increase of 2-3 €/MWh, depending on PTES capacity). By investing in 1 million m^3 of PTES capacity, the CO_2 emissions from heating and cooling can be lowered from approximately 6 kton/year to 1 kton/year (a reduction of over 80%). This strongly indicates that PTES could be a very relevant thermal energy storage technology for this system.

Figure 44 shows the effect of PTES storage on the indicators for different amounts of surplus heat inflow to the system. The positive effects of the storage on both indicators are more pronounced for high amounts surplus heat inflow than for low amounts. It is interesting that for 1 million m^3 PTES or larger, the indicators show the same results for a surplus share of 100% and 125%. This shows how investing in sufficient storage capacity enables more efficient usage of the incoming surplus heat, i.e. that over-dimensioning the surplus heat inflow compared to the system heat demand is not beneficial in case a sufficiently large thermal storage is available.

The results for ATES for the case of Rome are shown in Figure 45 and Figure 46. It can be seen that the introduction of ATES in the system substantially lowers both the thermal energy price and the CO_2 emissions. The best results for both indicators are obtained for the case of 60 °C surplus heat, 25 °C forward temperature and 10 °C return temperature. For this case, the thermal energy price has a slight optimum for an ATES volume of 1 million m^3 (water eq.). For an ATES of 1 million m^3 (water eq.), the CO_2 emissions in this case are lowered from around 6 kton/year to 2 kton/year (a reduction of approx. 65%). By increasing the ATES volume to 1.5 million m^3 (water eq.), the thermal energy price only increases by less than 1 €/MWh while the CO_2 emissions are lowered below 1 kton/year (a reduction of approx. 85%). These results clearly indicate that ATES can be highly suitable thermal energy storage technology for the type of system investigated here.

Figure 46 shows that investing in ATES has a positive effect both on the thermal energy price and on the CO_2 emissions regardless of how large the surplus heat inflow is compared with the heating demand in the system. Even for a surplus share of only 25%, CO_2 emission reductions of 40% can be obtained by investing in 1,5 million m^3 ATES (water eq.), while also lowering the thermal energy price. This indicates that ATES is a relevant solution for this type of systems, regardless of the scale of the surplus heat source compared to the total demand in the system.

The good performance of the ATES technology in the modelled system can largely be explained by the fact that it has dedicated warm and cold storages (in the form of separate drillings) and operates at temperatures (approx. 8 °C - 20 °C) very close to the cooling and heating temperatures in the FLEXYNETS concept (approx. 10 °C to 25 °C). This can save the system considerable amounts of external energy consumption for heating but especially for cooling, which results in reduced CO_2 emissions.

The results for BTES for the case of Rome are shown in Figure 47 and Figure 48. No BTES results are shown for conventional DH temperatures, as the *TRNSYS* model developed in this work was not designed to work with these temperature levels together with a borehole storage. The results in Figure 47 show that the introduction of relatively small BTES capacity (up to 200,000 m^3 water eq.) leads to a lowering of the thermal energy price, for all scenarios that have a high surplus heat temperature and FLEXYNETS forward and return temperatures. The introduction of 200,000 m^3 of BTES leads to a reduction in CO_2 emissions from around 6 kton/year to approx. 4.5 kton/year (a reduction of 25%). It can also be seen in the figure that the CO_2 emissions can be reduced from approx. 6 kton/year to approx. 1 kton/year (a reduction by 80%) by investing in 1 million m^3 (water eq.) BTES capacity. The thermal energy price for this size of BTES is roughly the same as with no BTES storage capacity. These results indicate that BTES could be a very relevant storage technology for this system.

It can be seen in Figure 47 that both the thermal energy price and the CO_2 emissions have an optimum for the case of high-temperature surplus heat and FLEXYNETS network temperatures. The most likely explanation for this is that the heat losses associated with BTES are rather large, and the required heating and cooling energy to make up for these losses increases as more water (with increasing storage size) is circulated in and out of the BTES (with corresponding losses in temperature). This could perhaps be improved upon by reducing the flow through the BTES, compared to the flow settings used in the calculations shown here.

Figures are grouped in one page per storage technology in the following four pages (TTES, PTES, ATES and BTES respectively). A summary of the results for all four thermal energy storage types for the case of Rome are shown in Figure 49 and Figure 50, for a 100% surplus share and for the temperature levels that performed best in most of the scenarios: 60 °C surplus heat temperature, 25 °C forward temperature and 10 °C return temperature.

The lowest thermal energy price (approx. 50% reduction compared to no storage) among these scenarios can be obtained by investing in 1 - 2 million m^3 of ATES (water equivalents), which also results in a large reduction in CO_2 emissions (approx. 60 - 85%). In case obtaining the largest possible CO_2 reductions has 1st priority, investing in 1.5 - 2 million m^3 PTES would be the best option. This would result in CO_2 emission reductions of over 90% and a thermal energy price 8 - 15 €/MWh higher than in the case of no storage (which is still more than 20 €/MWh lower than the assumed price in the network without the surplus heat availability). An investment in 1 million m^3 would reduce the CO_2 emissions by approx. 80% while increasing the thermal energy price by only 2 - 3 €/MWh.

Investing in BTES yields a slightly lower thermal energy price than PTES, but more CO_2 reductions for BTES volumes of 1 million m^3 (water eq.) or smaller. TTES performs well in reducing the CO_2 emissions, but is considerably more expensive than the other technologies for usage as a seasonal storage.

To illustrate the composition of the thermal energy price, an example for different PTES capacities for the case of Rome is shown in Figure 51. For reference, the CO_2 emissions are also shown in the graph. It can be seen that for small storage volumes (up to 200,000 m^3), the expenses for natural gas and electricity for heating and cooling are the principal component in the thermal energy price. As the storage volume increases, the expenses for gas and electricity shrink, but the system becomes heavier on capital costs and O&M costs due to the extensive investment in thermal energy storage. The CO_2 emissions decrease as the storage volume increases (for volumes above 100,000 m^3). Consequently, the expenses for CO_2 emissions, which account for approximately 10% of the thermal energy price for storage volumes of 200,000 m^3 or less, almost disappear for very large storage volumes. These general trends regarding the composition of the price also hold for other PTES scenarios and for scenarios with other storage types (TTES, ATES, BTES).

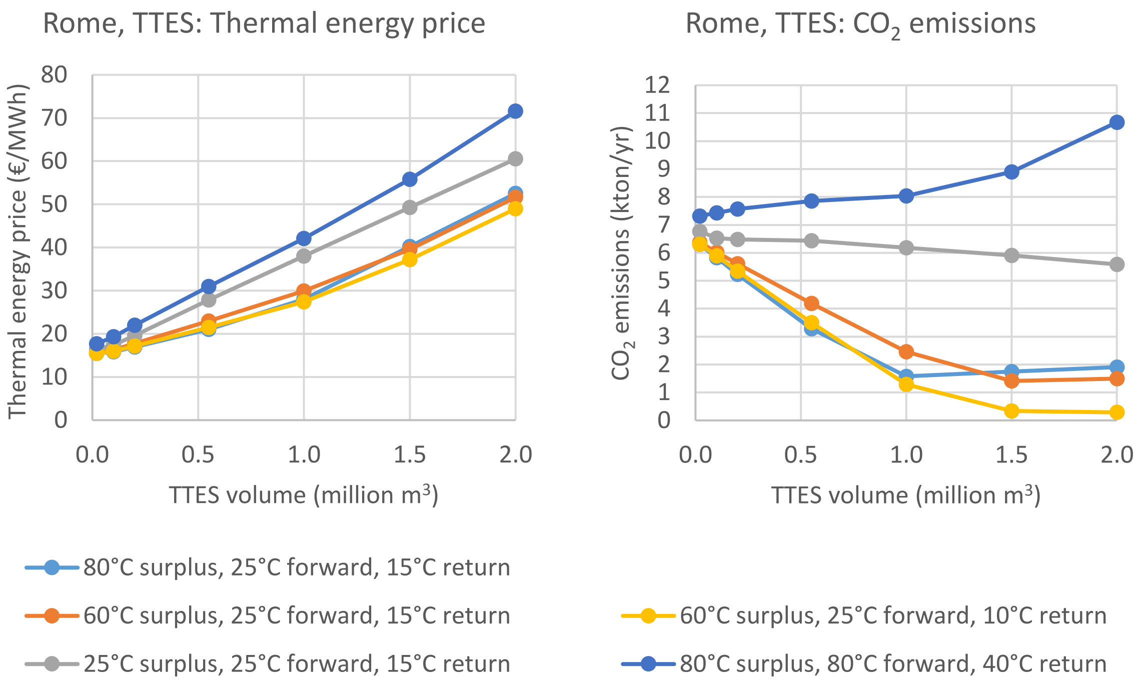


Figure 41 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%.

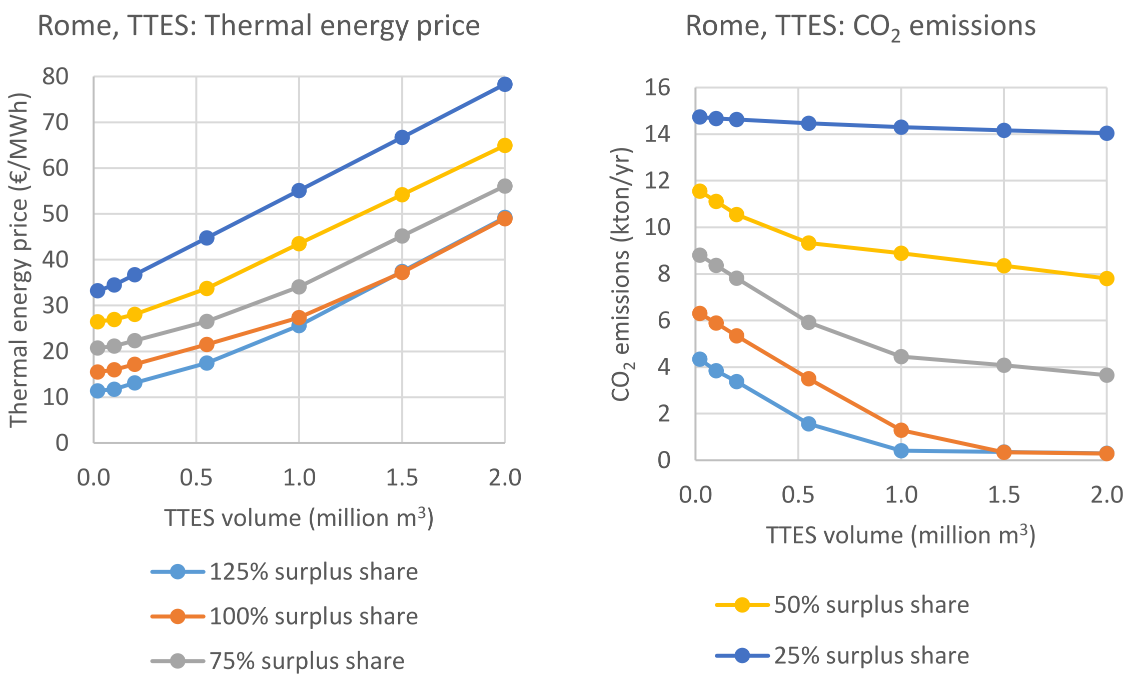


Figure 42 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

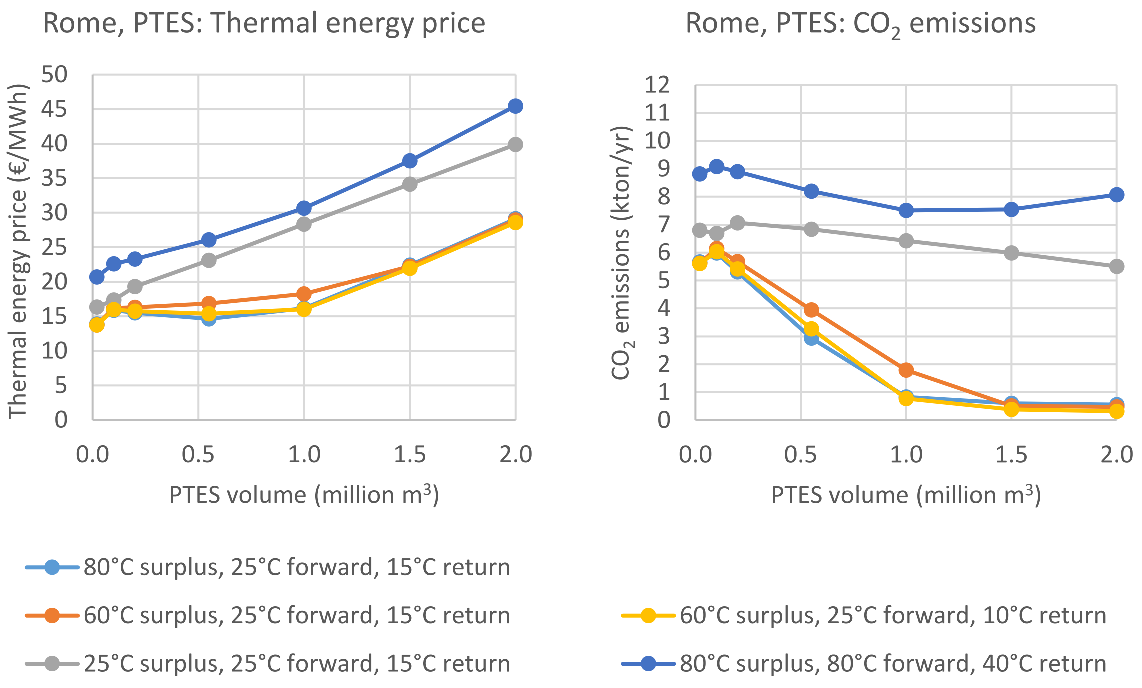


Figure 43 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%.

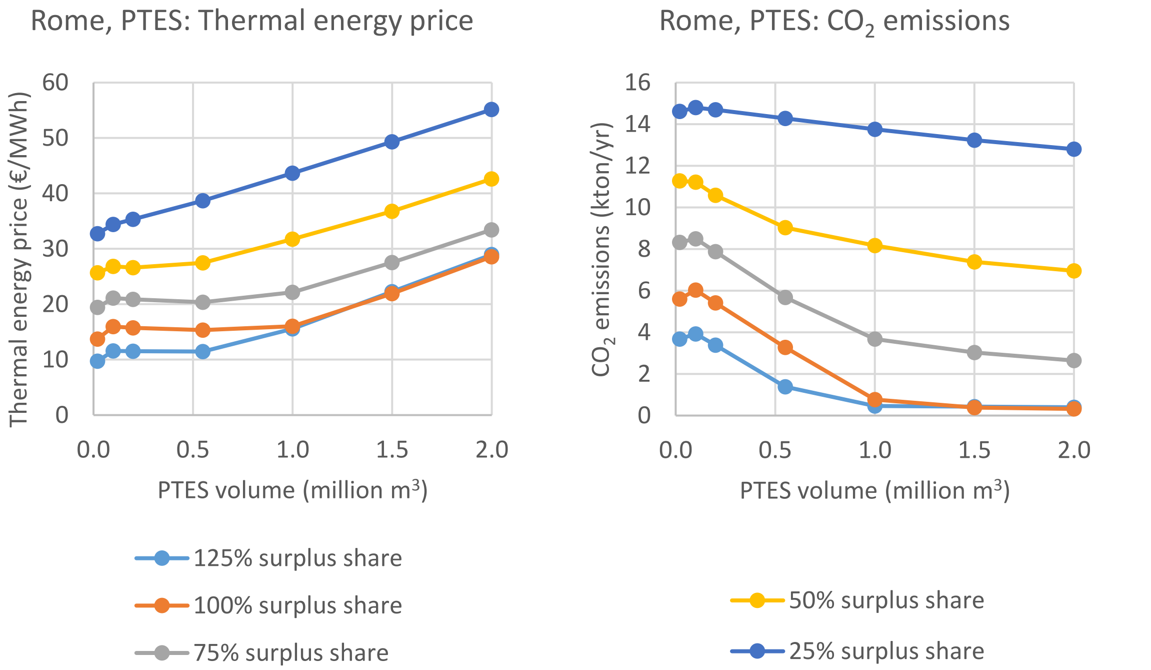


Figure 44 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

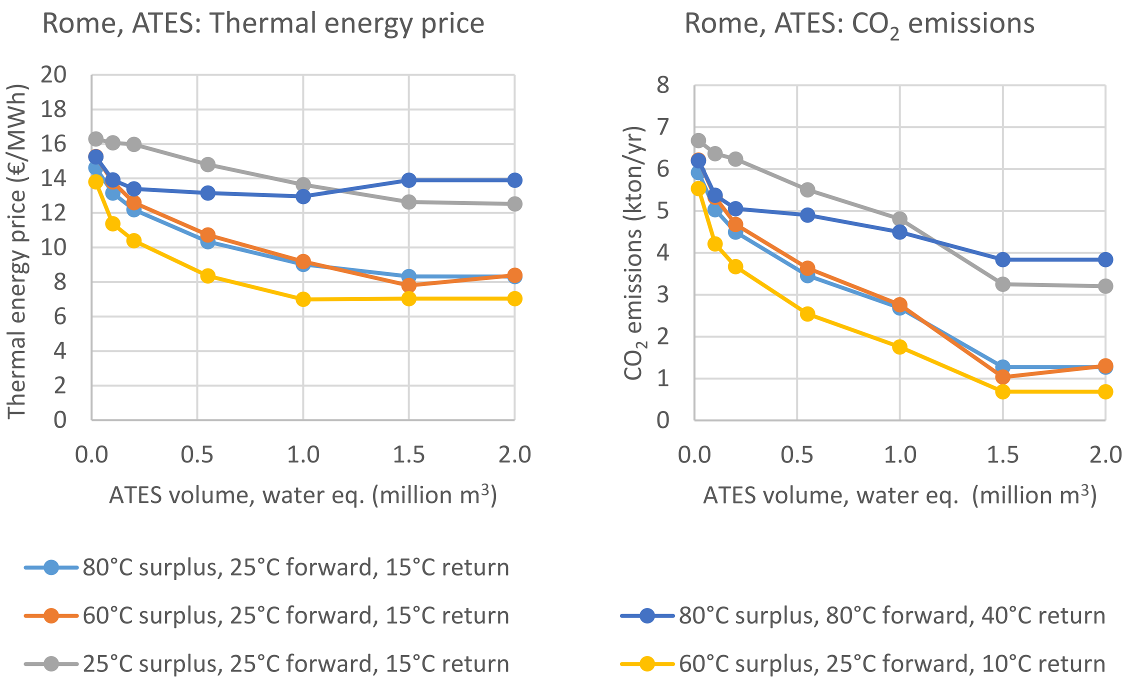


Figure 45 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%.

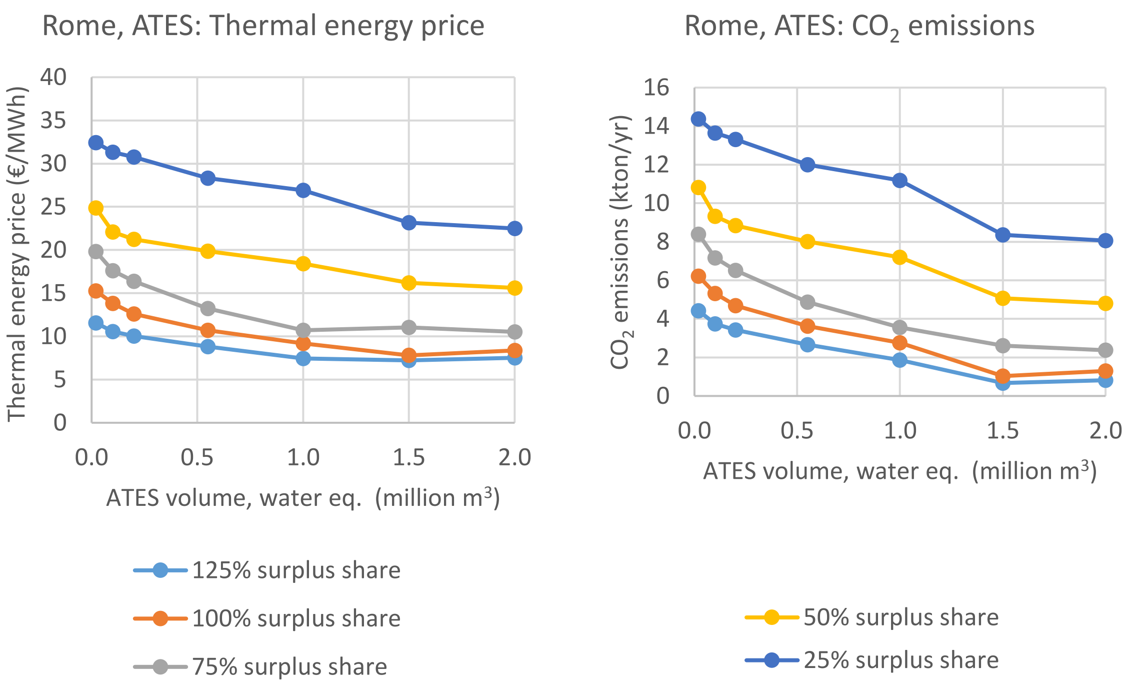


Figure 46 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

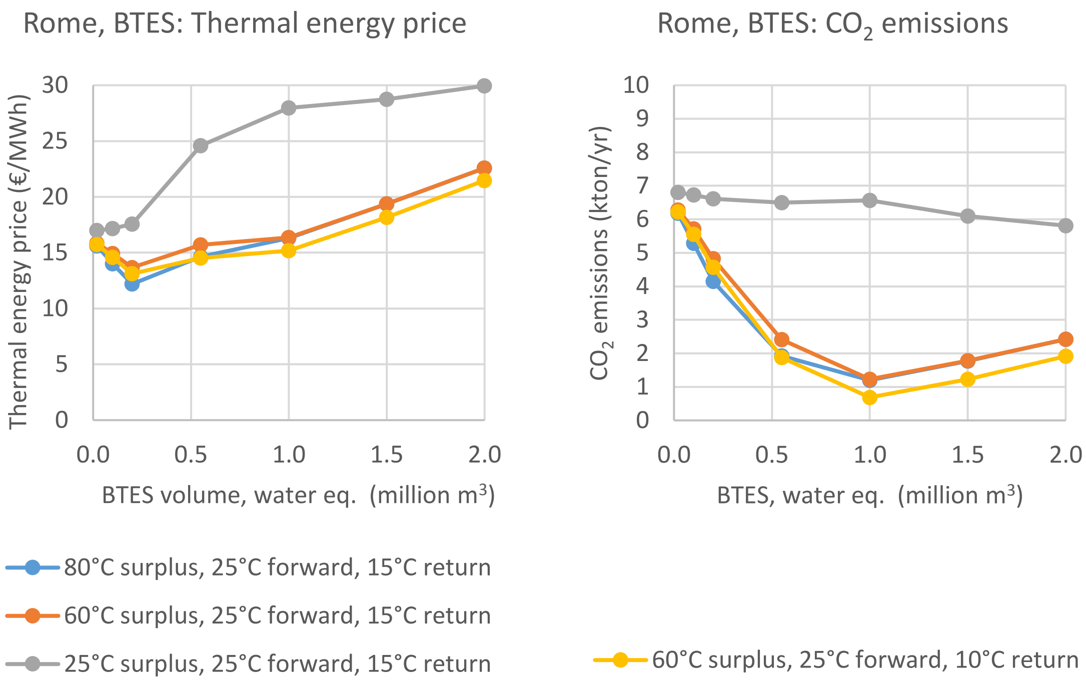


Figure 47 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%.

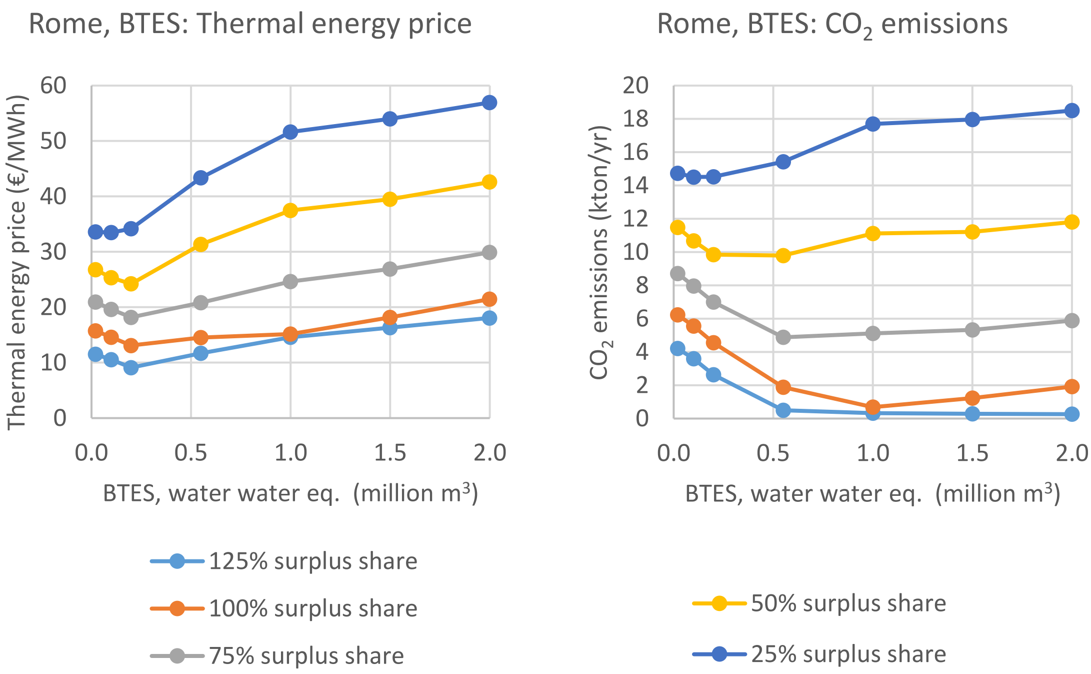


Figure 48 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

Though higher temperatures reduce the required volume to store a certain quantity of energy, there will often be a difference between the amount of available surplus heat depending on the temperature. Using the ATES case above as an example, it can be seen from Figure 45 and 46 that a surplus heat share of 100% at low temperature (grey line in Figure 45) should be more economically feasible than a 50% surplus heat share at 60 °C (yellow line in Figure 46). At the same time the CO_2 reductions are greater. Hence, it is not always most feasible to aim for high temperature surplus heat sources only.

In Figure 52 the thermal energy price is shown for 100,000 m^3 PTES for the case of Rome as a function of the length of the surplus heat transmission pipeline (all results shown before Figure 52 have assumed no transmission pipeline costs). Assuming a network heat price of 50 €/MWh without surplus heat availability, this price can be used as an upper limit for how far it could be economically feasible to source the surplus heat. For a surplus share of 100%, the results show that the transmission pipeline length can be up to 40 km before the thermal energy price equals 50 €/MWh. This distance should be understood as an upper limit to the feasible transmission pipeline distance, obtained based on the assumptions of the model. As these assumptions may not correspond to reality in all district heating and cooling systems, the real feasible distance can be considerably lower and must be evaluated individually based on local conditions. The results also show that this distance is slightly different for different PTES sizes and for different storage types (TTES, ATES, BTES), but the general conclusion is that for large shares of surplus heat (but not fitting the demand profiles) it is reasonable to consider the opportunity of large-scale storages even several kilometres away from the network. Based on the assumptions used in the model, the surplus heat can be sourced a few tens of kilometres away from the network before the thermal energy price exceeds 50 €/MWh.

As described in section 5.2, it is assumed that the heating demand that cannot be fulfilled using the surplus heat and the storage is fulfilled by operating a gas boiler with a generation price of 50 €/MWh. It should be noted here that in case the alternative to the surplus heat and storage is not a gas boiler, but another form of heat generation with different costs and CO_2 emissions (e.g. geothermal heat, oil boilers, electrical boilers, heat pumps etc.), the curves in all result figures will be shifted, based on the generation price and the CO_2 emissions associated with the given heat generation unit. In comparison, if the alternative to using surplus heat and storage is a heat source with lower marginal operation costs and lower CO_2 emissions per energy unit than the gas boiler (e.g. geothermal heat), the economic and environmental benefits of implementing surplus heat utilization will be smaller. Although the numerical values of the results will shift based on the alternative heat generation type in the system, it is nonetheless expected that the major trends and conclusions of the results shown here will remain the same.

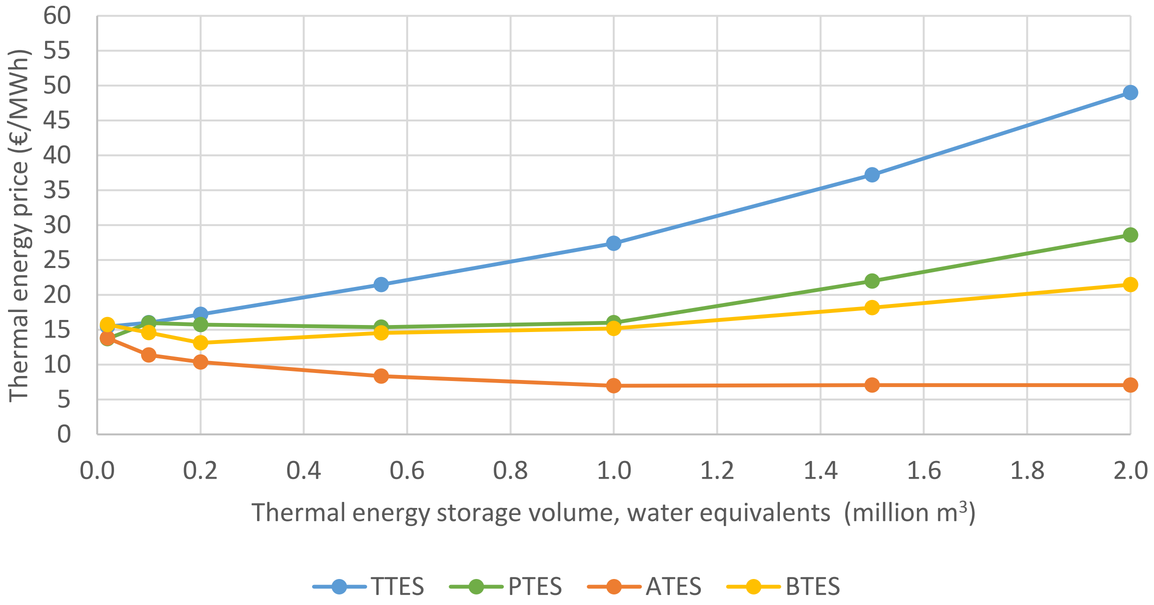


Figure 49 – The thermal energy price for all four thermal energy storage technologies, shown as a function of the storage volume. This is for the case of Rome, assuming no surplus heat transmission pipeline, a 100% surplus share and 60 °C surplus heat temperature, 25 °C forward temperature and 10 °C return temperature.

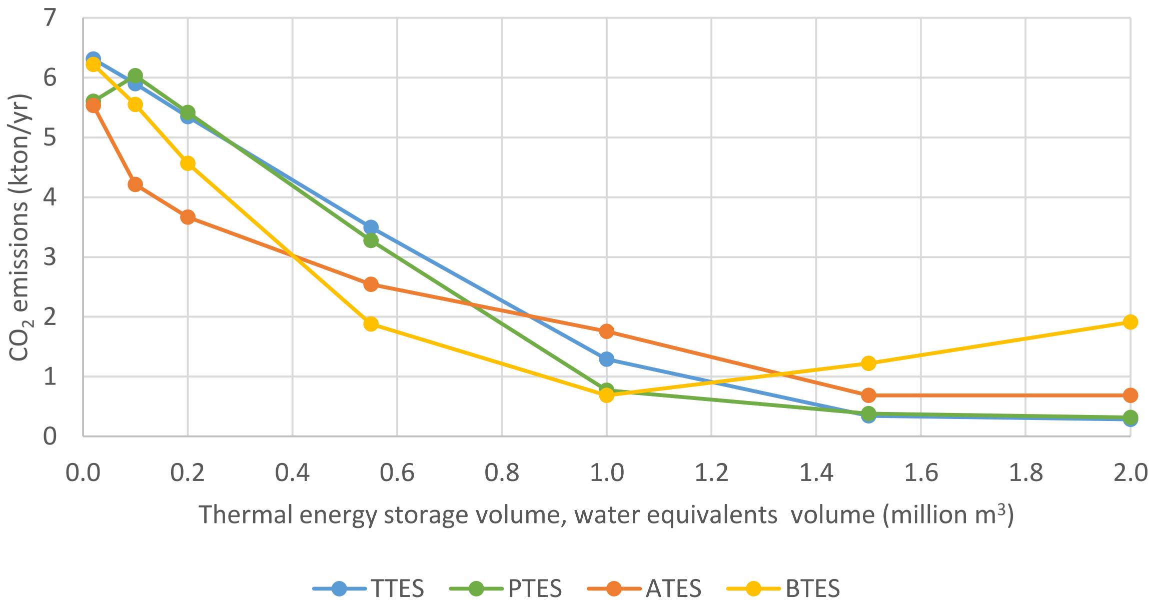


Figure 50 – The CO_2 emissions from external heating and cooling, for all four thermal energy storage technologies, shown as a function of the storage volume. This is for the case of Rome, assuming no surplus heat transmission pipeline, a 100% surplus share and 60 °C surplus heat temperature, 25 °C forward temperature and 10 °C return temperature.

For BTES the CO_2 emission minimum indicates that at some point (volume) there is no need for further m^3 of storage. Increasing the storage volume beyond this point will only increase the modelled heat losses as the available heat is spread over a larger volume thus increasing the losses.

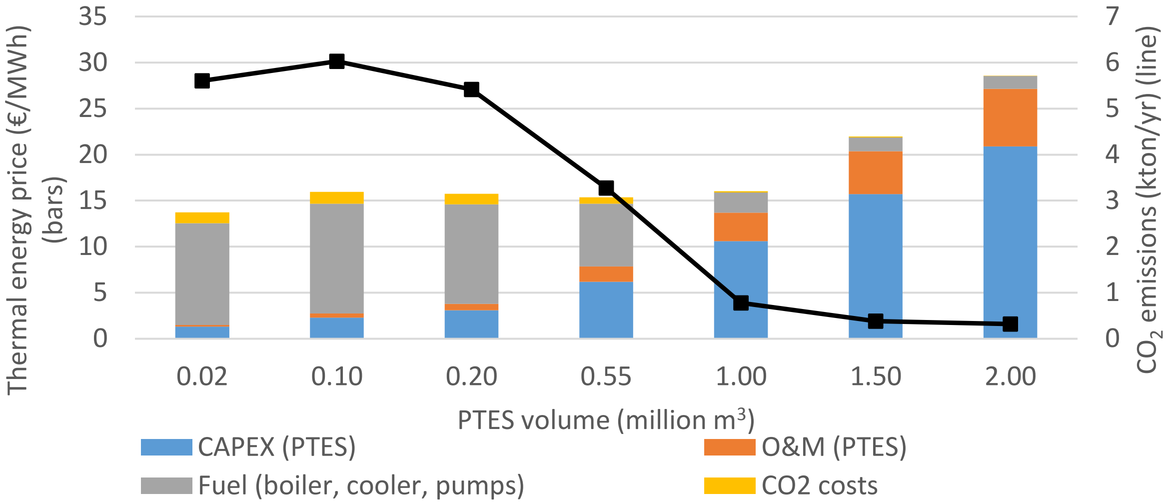


Figure 51 – The calculated thermal energy price composition (bars) and CO_2 emissions (line) for different PTES volumes. This is for the case of Rome, assuming no surplus heat transmission pipeline, a 100% surplus share and 60 °C surplus heat temperature, 25 °C forward temperature and 10 °C return temperature.

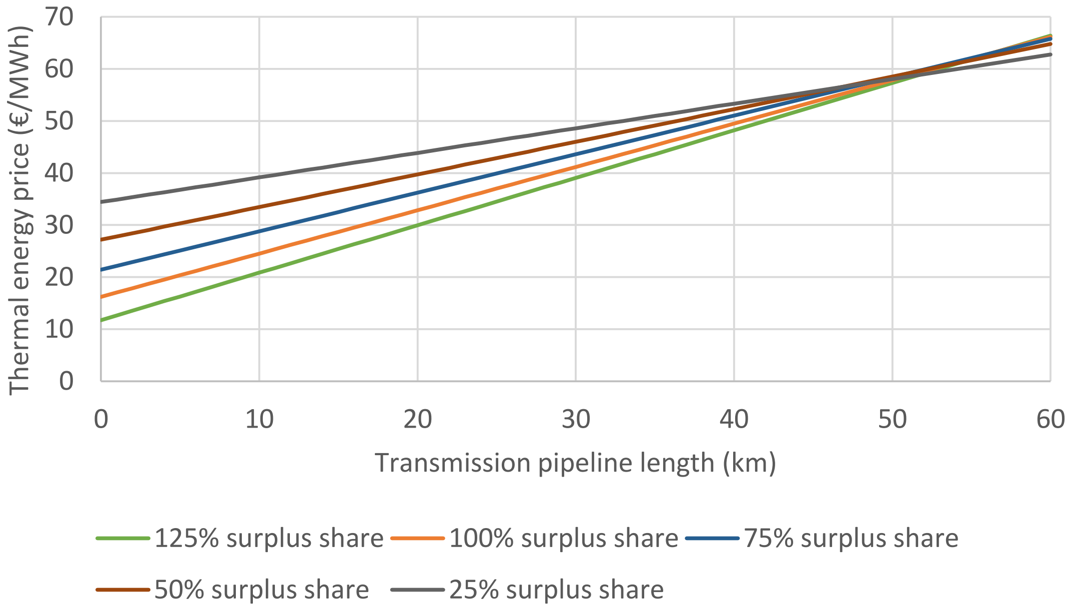


Figure 52 - Rome: Thermal energy price and transmission pipeline length. 100,000 m³ PTES volume, 60 °C surplus, 25 °C forward, 15 °C return. If the network heat price is 50 €/MWh, a transmission pipeline of up to around 40 km could be economically feasible in case of 100% or higher surplus heat share.

5.6.3 Reference case: London

The results for all four thermal energy storage types for the case of London are shown in Figure 53 and Figure 54, for a 100% surplus share and for the temperature levels that performed best in most of the scenarios: 60 °C surplus heat temperature, 25 °C forward temperature and 10 °C return temperature. The full results for the case of London can be seen in Figures 57 to 64 in Appendix A.

The general trends and overall conclusions remain the same for the London case as for the case of Rome, although the numerical values for both the thermal energy price and the CO_2 emissions are generally lower for the London case. The lowest thermal energy price among the London scenarios can be obtained by investing in 1 million m^3 (water eq.) of ATES capacity, which results in a more than 50% reduction in the thermal energy price compared to a situation with no storages. This also results in some of the largest CO_2 emission reductions, of more than 95% compared to the case of no storage. Similar CO_2 emission reductions can be obtained by investing in 1 million m^3 of PTES, but this increases the thermal energy price by around 4 €/MWh compared to the no storage case. Similar to the case of Rome, the performance of BTES lies in between that of ATES and PTES for both indicators (at least for BTES sizes up to 200,000 m^3 water eq.). These results clearly indicate that the usage of large-scale thermal energy storages, especially ATES and to some degree PTES and BTES, would be very relevant for balancing supply and demand in the modelled system for the reference city of London.

The only differences between model input values for the case of London and the case of Rome are in the time series for the ambient temperature, the heating demand and the cooling demand (described in Section 5.5) and in the size of the cooling demand (see Table 5.4). The assumed annual cooling demand in the case of London is 7.5 GWh/year, compared to 25 GWh/year in the case of Rome. The annual heating demand is assumed to be 100 GWh/year in both cases. The difference in the annual cooling demand largely explains why the thermal energy price and the CO_2 emissions are generally lower for the London case than for Rome. Providing cooling using the chiller (heat pump) is more expensive for the system than heating, because a large fraction of the heat can be obtained free of charge as surplus heat. A lower cooling demand therefore directly lowers the thermal energy price. The same is true for the CO_2 emissions. More CO_2 is emitted when providing cooling than heating, because the surplus heat utilization is not assumed to lead to increased CO_2 emissions in the system. A lower cooling demand therefore directly lowers the annual CO_2 emissions. In the case of London, most of the cooling demand can be supplied by the cold contents of thermal energy storages, if a 1 million m^3 or more ATES or PTES storage capacity is present. Therefore, the CO_2 emissions in these scenarios come very close to being eliminated in this case, as can be seen in Figure 54.

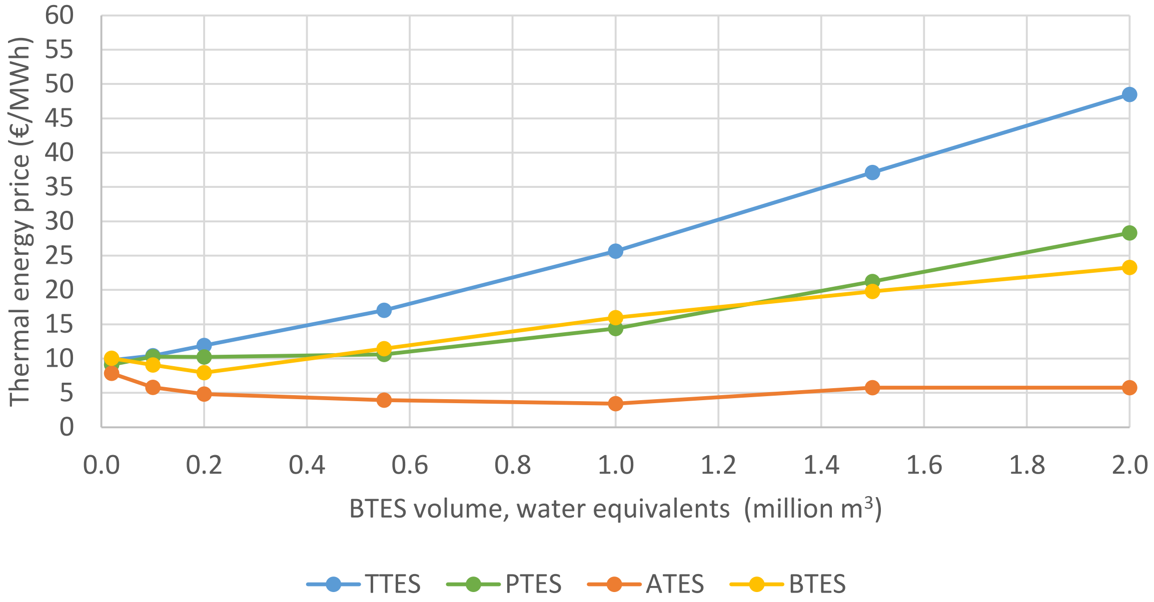


Figure 53 – The thermal energy price for all four thermal energy storage technologies, shown as a function of the storage volume. This is for the case of London, assuming no surplus heat transmission pipeline, a 100% surplus share and 60 °C surplus heat temperature, 25 °C forward temperature and 10 °C return temperature.

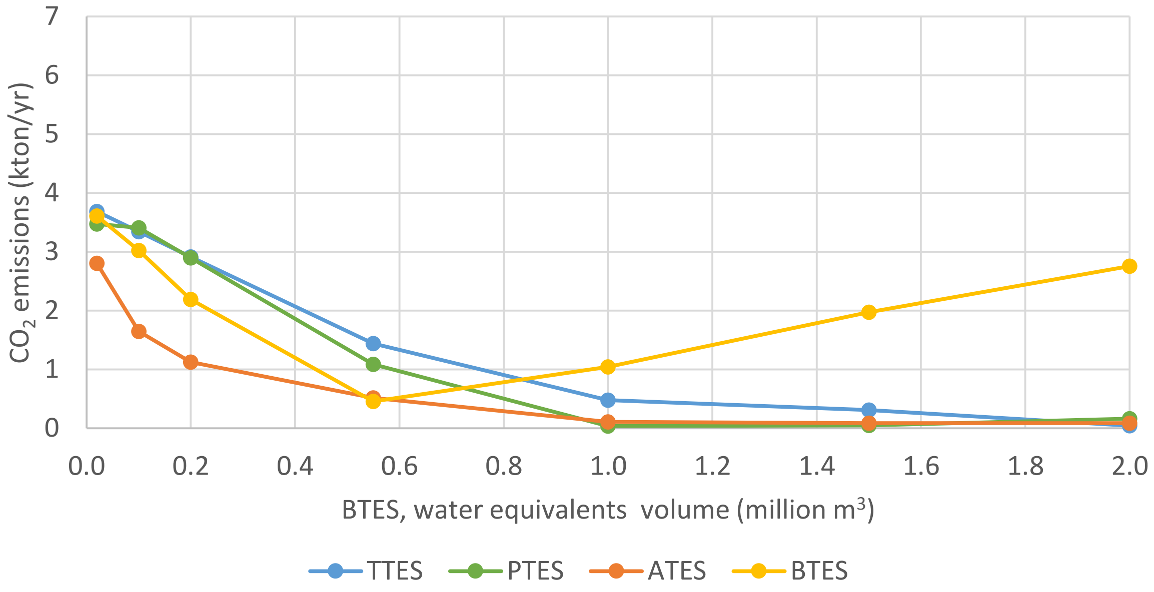


Figure 54 – The CO_2 emissions from external heating and cooling, for all four thermal energy storage technologies, shown as a function of the storage volume. This is for the case of London, assuming no surplus heat transmission pipeline, a 100% surplus share and 60 °C surplus heat temperature, 25 °C forward temperature and 10 °C return temperature.

5.6.4 Reference case: Stuttgart

The results for all four thermal energy storage types for the case of Stuttgart are shown in Figure 55 and Figure 56, for a 100% surplus share and for the temperature levels that performed best in most of the scenarios: 60 °C surplus heat temperature, 25 °C forward temperature and 10 °C return temperature. The full results for the case of Stuttgart can be seen in Figures 65 to 72 in Appendix A.

The general trends and overall conclusions remain the same for the Stuttgart case as for the case of Rome and London. The numerical values in the Stuttgart case are generally in between the values in the case of Rome and in the case of London, and generally extremely close to those for the case of London. The lowest thermal energy price in the Stuttgart scenarios can be obtained for the scenario with 1 million m^3 (water eq.) ATES capacity, which gives a 50% reduction in the price compared to no storage. This leads to a CO_2 emissions reduction of approx. 90%. Even more CO_2 reductions can be obtained by investing in 1 million m^3 of PTES, or more than 95% lower CO_2 emission compared to a situation with no thermal energy storages. PTES is, however, more expensive than ATES and investing in 1 million m^3 PTES capacity leads to an increase in the thermal energy price by 5 €/MWh. The performance of BTES lies in between that of the ATES and PTES technologies, for BTES volumes up to 200,000 m^3 (water eq.).

The assumed annual cooling demand in the case of Stuttgart is 10 GWh/year, compared to 7.5 GWh/year for London and 25 GWh/year in the case of Rome. The annual heating demand is assumed to be 100 GWh/year in all cases. Similar to the case of London, the difference in cooling demand largely explains why the thermal energy price and the CO_2 emissions are generally lower for Stuttgart than for Rome and marginally higher for Stuttgart than for London. The reasoning behind this for the Stuttgart case is the same as explained for the case of London.

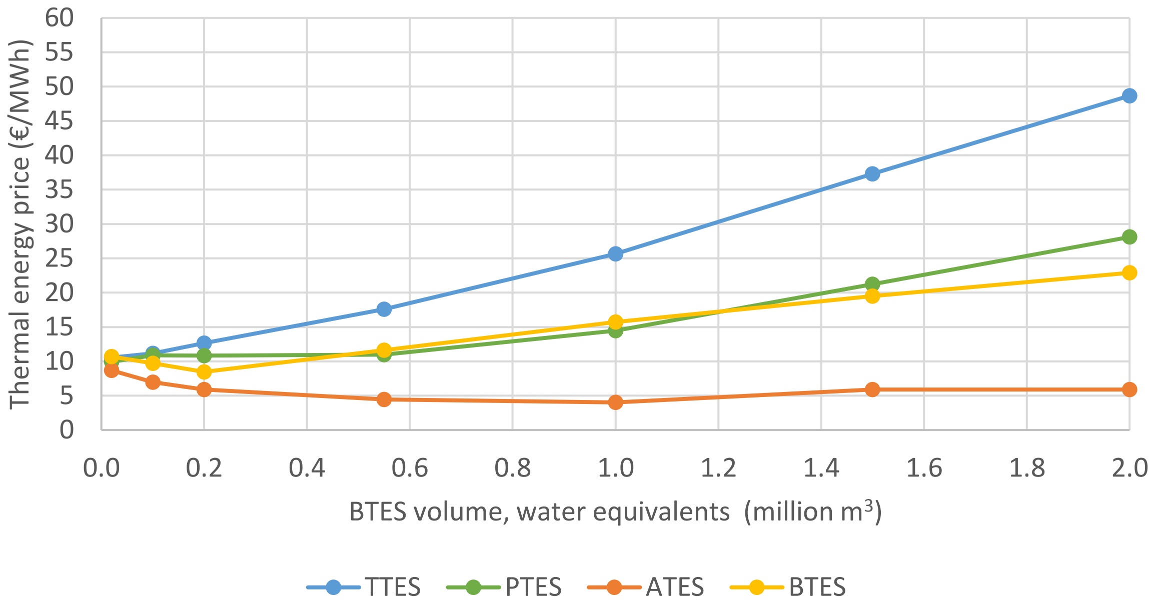


Figure 55 – The thermal energy price for all four thermal energy storage technologies, shown as a function of the storage volume. This is for the case of Stuttgart, assuming no surplus heat transmission pipeline, a 100% surplus share and 60 °C surplus heat temperature, 25 °C forward temperature and 10 °C return temperature.

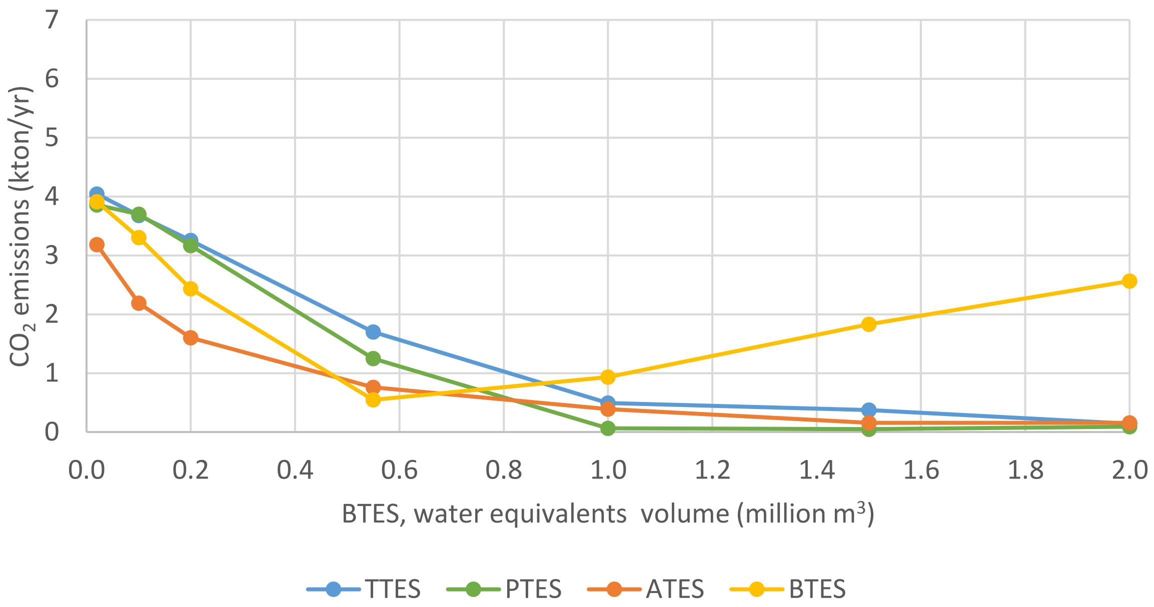


Figure 56 – The CO_2 emissions from external heating and cooling, for all four thermal energy storage technologies, shown as a function of the storage volume. This is for the case of Stuttgart, assuming no surplus heat transmission pipeline, a 100% surplus share and 60 °C surplus heat temperature, 25 °C forward temperature and 10 °C return temperature.

5.7 TRNSYS model discussion

The results indicate that PTES, ATES and BTES can all be suitable solutions for balancing thermal energy supply and demand on a seasonal basis in the system investigated here. The results for all three technologies show that investing in such thermal energy storage capacity can significantly lower the system's annual CO_2 emissions associated with heating and cooling (by up to 95%). One example is seen in the case of Figure 51 where the CO_2 emissions can be reduced by 37% if an increase in average cost (€/MWh) of 13% is considered acceptable. Similarly, an even bigger storage could lower the CO_2 emissions by 85% if a price increase of 17% is acceptable. This shows that the utilization of large-scale thermal energy storages can be very relevant in the FLEXYNETS concept, in case a source of "high-temperature" surplus heat is available (i.e. higher than the network forward temperature, but similar to conventional DH temperatures).

The promising results obtained for the usage of ATES are backed up by the fact that there are already more than 1000 aquifer storages in operation in systems where there is both a heating and a cooling demand. The principle of the ATES technology, which has separate heat and cold storages in the form of warm and cold wells with operating temperatures between approx. 8 °C and 20 °C, makes it very well suitable for integration with the FLEXYNETS concept due to the similar temperature levels. It should of course be mentioned that the actual suitability of ATES can be very case-specific, in that it relies on suitable geological conditions at the site in question.

The PTES technology is already used at conventional district heating temperatures in Denmark, with further PTES projects being planned in other countries. The results indicate PTES facilities with good stratification can be used for both heat (at the top) and cold storage (at the bottom) and that they can effectively reduce CO_2 emissions associated with both heating and cooling. The PTES cost is somewhat higher than the cost of ATES, based on the price assumptions used in this report. PTES could be a very relevant option in case ATES is not suitable, e.g. due to geology or the desired storage scale (as each ATES system is typically smaller than each PTES).

The BTES technology is also used already, mainly for heat storage. BTES is e.g. used in connection with a low-temperature district heating network in Drake Landing, Canada. The results indicate that it could be a relevant technology for heat and cold storage by operating separate warm and cold wells, similar to the ATES operating strategy. BTES could be very relevant in areas where ATES is not suitable due to geological conditions.

The TTES technology was modelled as a seasonal storage for comparison with the other technologies. TTES is a mature and widely used technology, but is usually only considered viable for shorter term storage (daily to weekly storage). The results indicate the same, that TTES is too expensive to become relevant as a seasonal storage in the FLEXYNETS concept. TTES does, however, serve an important role as buffer storages in the case of ATES and BTES, absorbing daily to weekly fluctuations in thermal energy supply and demand that may be too fast for the relatively slowly responding underground storage technologies.

In the cases where both the indicators (cost and CO_2 emissions) are lowered by introducing thermal storages, it is clear that the implementation of storages could help both in reaching the goal of the cheapest energy for the consumers and/or any targets regarding the reduction of CO_2 emissions. In case the two indicators show different trends (increased cost but reduced CO_2), the choice of whether or not to implement thermal storage in the system (and to how large an extent) depends on which of the two indicators is more important to the policy makers; if lowering the thermal energy price has first priority or if reducing the CO_2 emissions is considered most important. Supplying energy at the lowest possible price may not be the foremost goal e.g. if national and international goals and treaties on CO_2 emissions reduction cannot be fulfilled at the same time. The right balance between the two indicators is therefore a question of policy, and for this reason the two indicators have not been weighted here and combined into a single scenario performance number.

The results show that the transmission and storage of surplus heat at higher temperatures (60-80 °C) generally leads to lower thermal energy prices than the transmission and storage of surplus heat at the assumed forward temperature of FLEXYNETS (25 °C), when comparing identical quantities of thermal energy supply. It should, however, be noted that in case very large amounts of surplus heat are available at low temperature (25 °C) but only smaller amounts are available at higher temperatures (60-80 °C), it can be more beneficial to choose the low temperature surplus heat rather than the high temperature surplus heat. This can be seen in the result graphs (e.g. Figure 41-48) by noting that the transmission and storage of surplus heat at 25 °C and 100% surplus share generally leads to a lower thermal energy price and lower CO_2 emissions than the transmission and storage of surplus heat at 60 °C and 25% surplus heat. It is therefore very important to take both the temperature levels as well as the available quantities of surplus heat into account when considering which option of surplus heat utilization is most beneficial.

As already mentioned, the exact choice of thermal energy storage technology is very case- and location-specific, as it depends on site-specific factors such as the geological suitability for ATES or BTES and the availability of land area for PTES. The results presented here are, furthermore, associated with considerable uncertainty. The investment costs for ATES and BTES are based on fits to data sets with only few points, due to lack of more data. The heating and cooling demand profiles for the three reference cities are based on calculated profiles, rather than statistics (due to lack of available statistics). The *TRNSYS* components used for modelling the thermal energy storages cannot model all physical aspects of the storages accurately for all cases, especially regarding the underground properties of ATES and BTES, since these are always site-specific. As mentioned in Section 5.1.2, the *TRNSYS* model layout is merely an approximation of the envisioned system, which is described in Section 5.1.1. Using *TRNSYS* and its specialized thermal energy storage components to simulate various scenarios is however expected to provide a reliable picture of the general trends and effects in the modelled system when the different thermal energy storage technologies are introduced.

The results indicate that a surplus heat transmission pipeline distance up to approx. 40 km (see Figure 52) can be viable in case the assumptions used in this model are valid, in case surplus heat can be obtained free of charge from the source and in case the thermal energy price without the surplus heat is 50 €/MWh. To compare this result with existing pipelines, it can be mentioned that a few insulated, high-temperature district heating pipelines on this length scale already exist between geothermal heat sources and district heating networks in Iceland. In the context of the topic of this chapter, the geothermal sources may be thought of as cheap surplus heat sources. A 27 km long pipeline with a nominal diameter of 800 mm transmits up to 300 MW of heat to the Reykjavík city area (population approx. 200,000). The temperature drop in this highly-insulated pipeline is 0.4 – 2 K, depending on the load. A much narrower 34 km pipeline supplies heating to the town of Borgarnes (population approx. 2,000), with the temperature dropping by around 9 K on the way. A 64 km pipeline (possibly the longest district heating transmission pipeline in the world) supplies the town of Akranes (population approx. 7,000), with the temperature dropping by around 18 K on the way. Long district heating transmission pipelines also exist in Sweden, where a 29 km long pipeline connects the district heating networks of the cities of Helsingborg (population approx. 140,000) and Lund (population approx. 89,000).

6 Summary and conclusions

In this report, the potential role of large-scale thermal energy storages in the FLEXYNETS concept has been analyzed. The report focuses on four storage types; tank, pit, aquifer and borehole storage. Some general principles of thermal energy storages, such as time scales, temperatures, volume, storage medium and investment costs have been described and quantified in the context of FLEXYNETS. The physical and economic properties of the four storage types have been analyzed and presented. The analysis shows that regardless of the storage technology, the required storage volume and investment costs are highly dependent on the temperature difference in the storage though the economy of scale in general is favourable for these large-scale storages. As the FLEXYNETS concept works with very low temperature differences between forward and return temperatures (approx. 5-15 K difference), this would require any thermal energy storages that work at the FLEXYNETS network temperature to be large and expensive, compared to storages working at conventional district heating temperatures. However, some storage types (e.g. ATES) cannot store heat at the level of conventional DH, and the drawback of having somewhat lower supply temperature to the storage is therefore minimised.

Furthermore, transmission pipeline costs for the utilization of surplus heat, which is an important aspect of the FLEXYNETS concept, have been analyzed. The results suggest that sourcing surplus heat at even several kilometres away from the FLEXYNETS network may be economically feasible, as long as the surplus heat source is sufficiently large compared to the network heat demand. However, this highly depends on the actual cost of both the transmission line, the utilisation of the surplus heat and the alternative heat supply. In conclusion it is worth remembering that in some cases it may be worthwhile to investigate surplus heat options even “far away” from the actual network area.

Based on this, situations have been identified in which large-scale thermal energy storages could be most relevant in the FLEXYNETS concept. In general, the most favourable solutions involve surplus heat available at temperatures higher than the FLEXYNETS network temperature. In that case this heat is directly transferred, via a transmission pipeline, to a thermal energy storage. The storage can then take advantage of the larger temperature difference between the surplus heat temperature and the FLEXYNETS cold pipe temperature, which lowers the required storage volume and investment compared to operating only at FLEXYNETS temperatures. However, if the amount of surplus heat is significantly higher at approx. the FLEXYNETS temperature level, it may be more beneficial to choose a connection to this low temperature heat source. Also in this case it may be feasible to include a storage even though the required volume will be significantly higher to store a certain quantity of energy. This point is especially relevant for ATES which cannot in any case store heat at high temperature and has a low marginal specific investment cost. In that case the savings in the alternative heat supply may outweigh the added cost of an increased storage volume requirement.

The storages can balance fluctuations in surplus heat supply and network heating and cooling demands, thereby facilitating more efficient usage of the incoming surplus heat and reducing the auxiliary energy supply (and any associated CO_2 emissions) needed for satisfying the heating and cooling demand in the network.

This system has been modelled in the simulation software *TRNSYS*. The simulations have been carried out for all four thermal energy storage types and for three reference cities; Rome, London and

Stuttgart. The simulations have furthermore been performed for different operating temperatures and for different amounts of surplus heat availability. The results of the simulations have been evaluated based on two indicators; the average thermal energy generation cost in the system (in €/MWh) and the annual CO_2 emissions arising from satisfying the heating and cooling demand in the system (in kton/year).

The results of the simulations show that especially ATES but also PTES and BTES can be very relevant as seasonal storage in the FLEXYNETS concept, in case surplus heat is available to the system. Investing in such thermal energy storages can significantly lower the system's annual CO_2 emissions associated with heating and cooling (by up to 95% in investigated scenarios), and either lower the thermal energy price (in investigated scenarios up to 50%) in the system or at least keeping it at a similar level compared to a system without the storage. These storages' properties will be an important part of the decision process for any given case. As described in this report, they all have different benefits and drawbacks depending on the system they are a part of. The conclusion is therefore that although large-scale thermal energy storages are not always relevant for the FLEXYNETS concept, they can be very beneficial to the system in certain cases, in particular if the network in question has a certain size and if surplus heat is available in large quantities. Centralized storage options are therefore worth to be considered when evaluating specific cases in more detail.

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Appendix A: TRNSYS results for London and Stuttgart

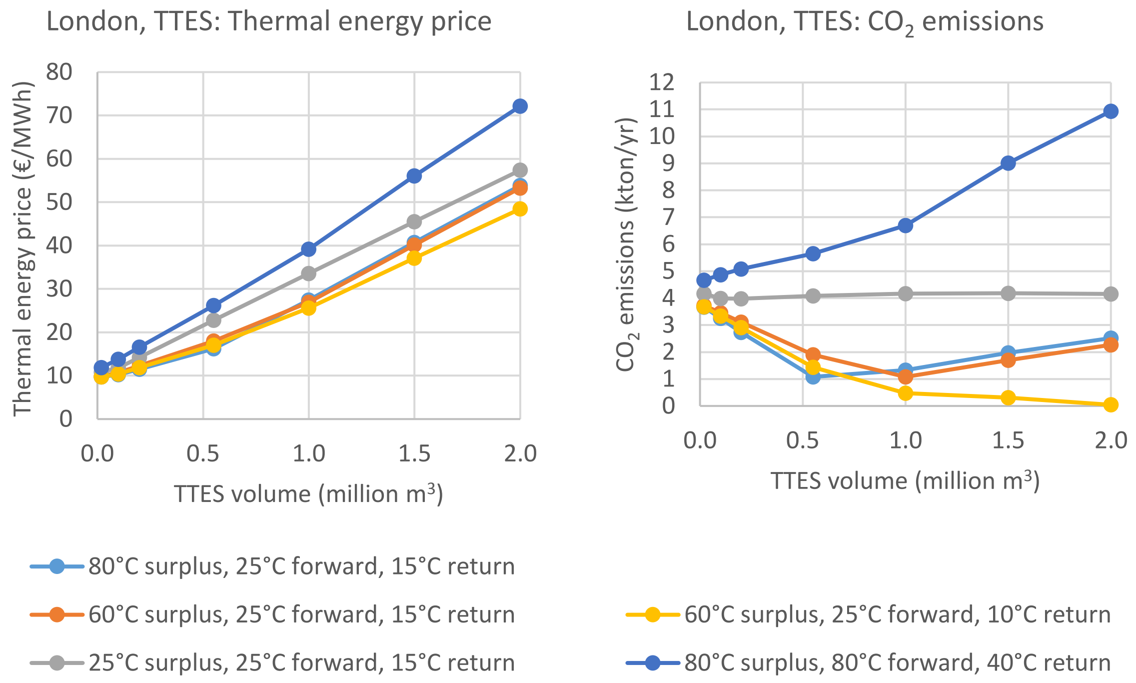

Figure 57 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%.

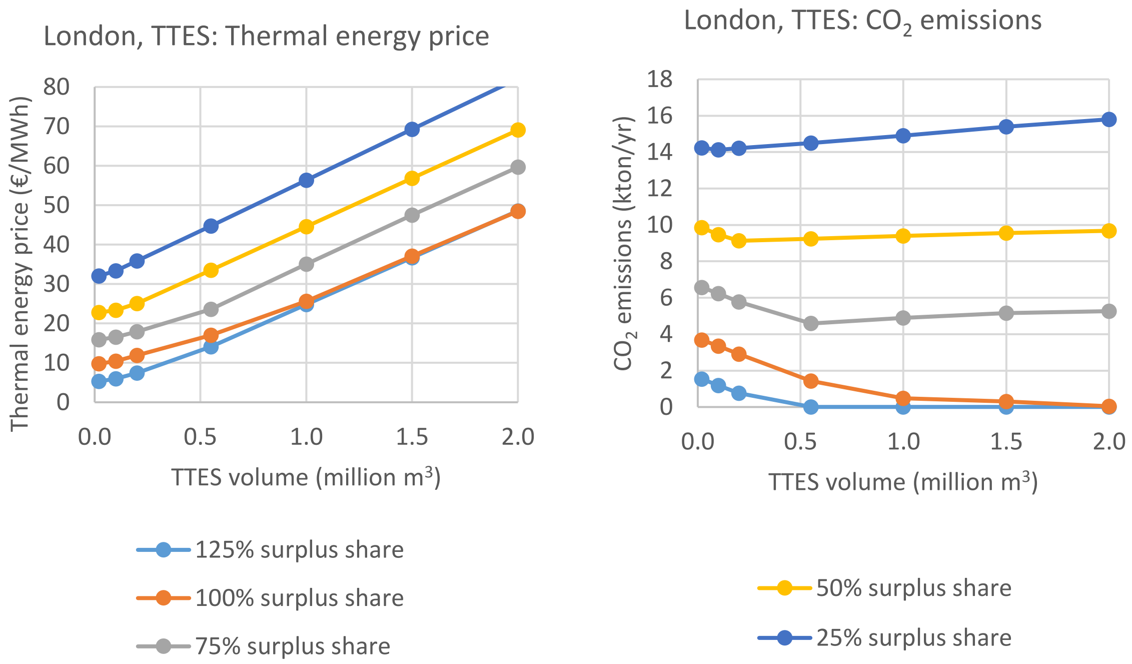

Figure 58 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

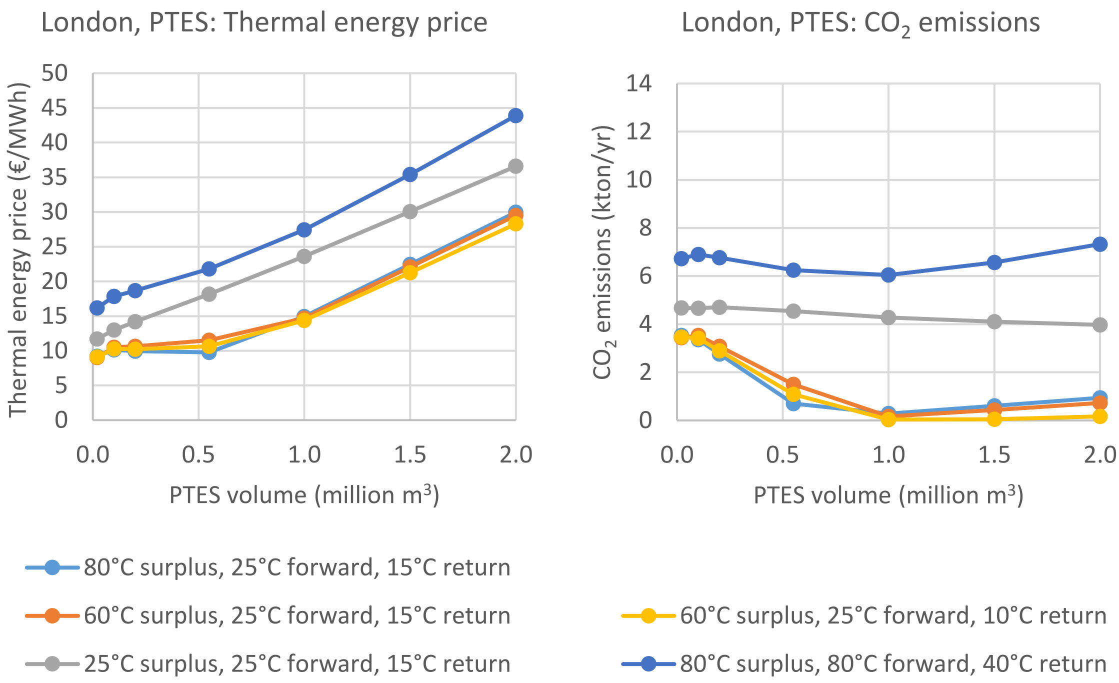

Figure 59 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%.

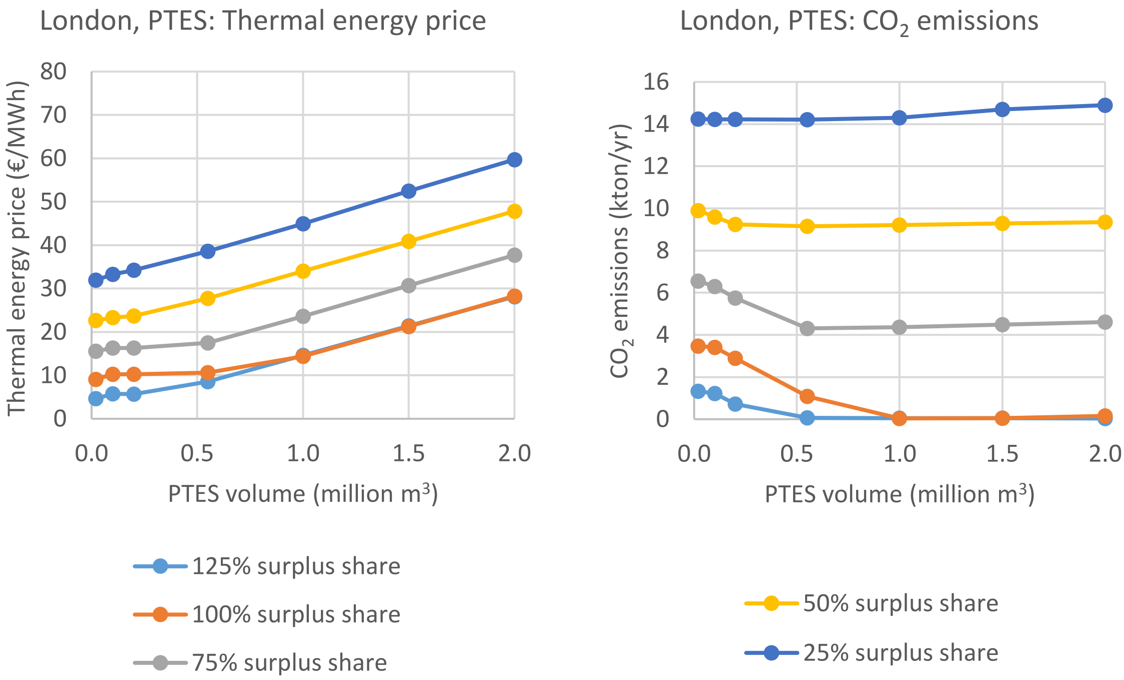

Figure 60 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

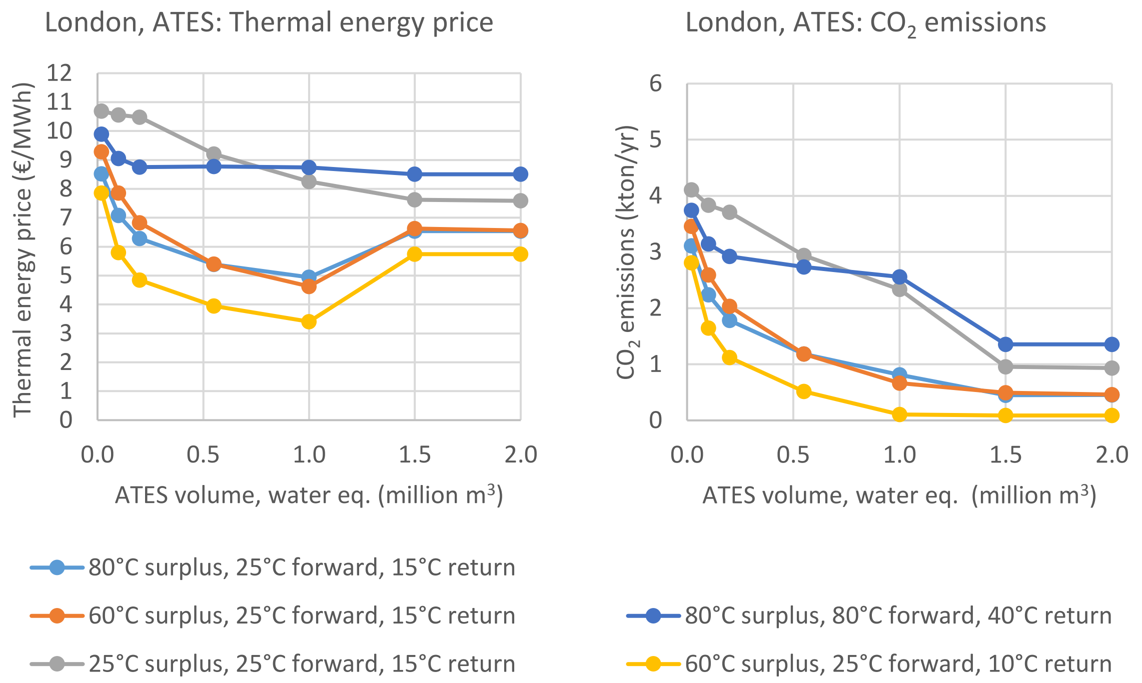

Figure 61 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%.

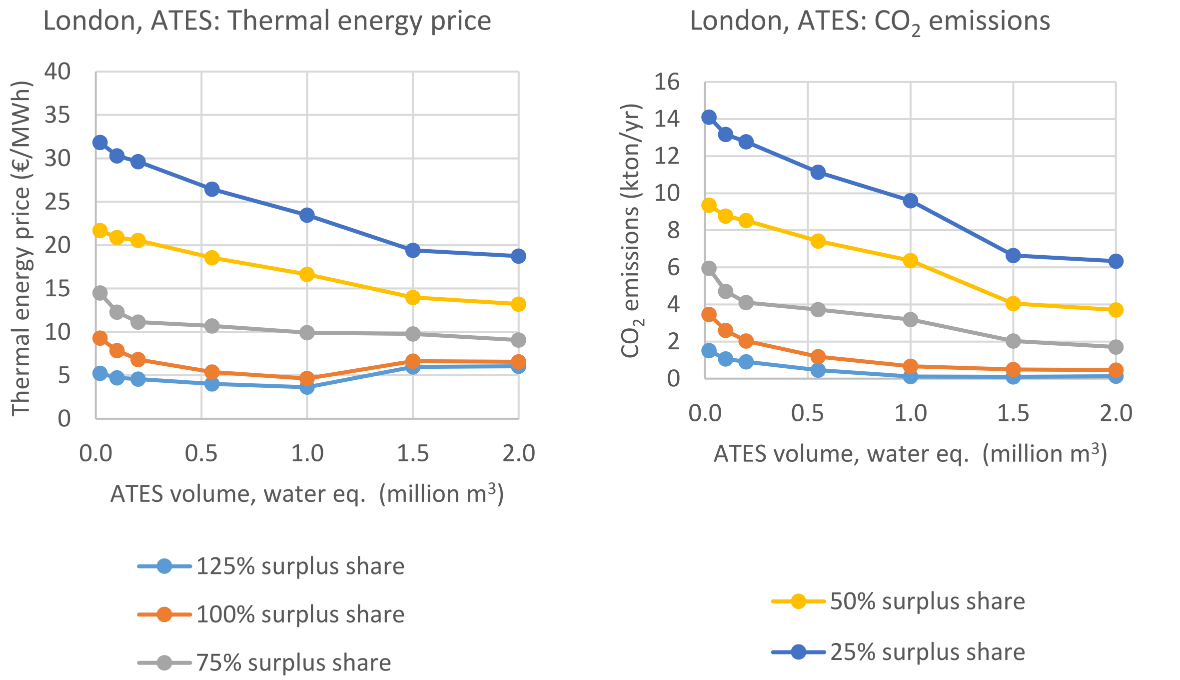

Figure 62 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

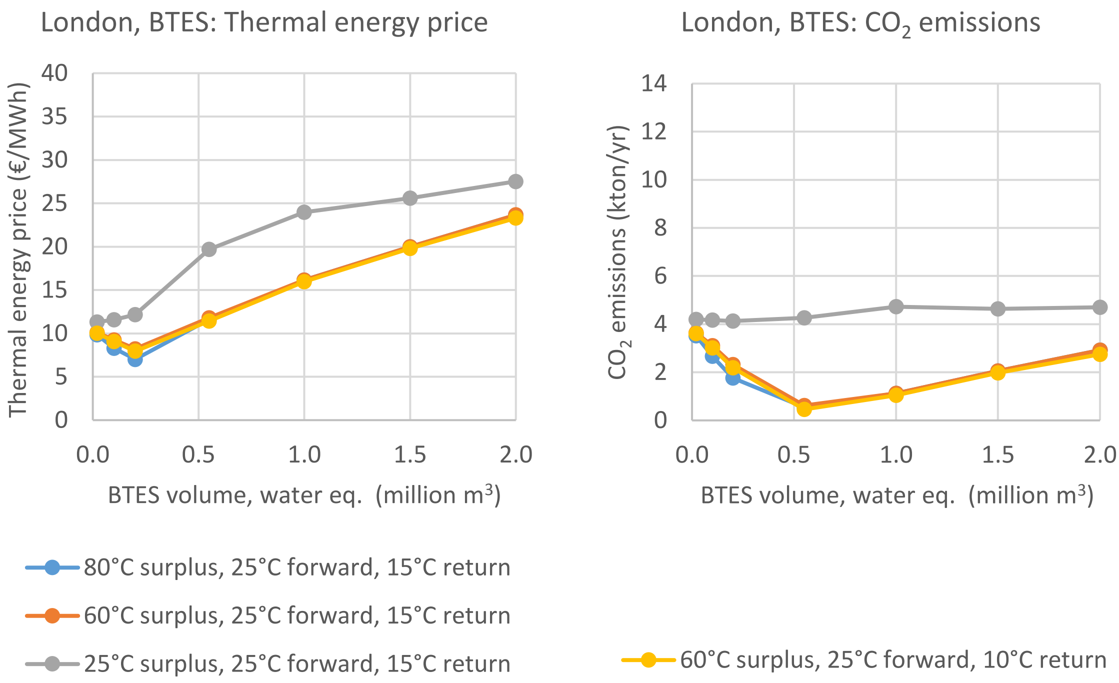

Figure 63 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%. For the largest storage volumes, the blue, orange and yellow curves are almost identical.

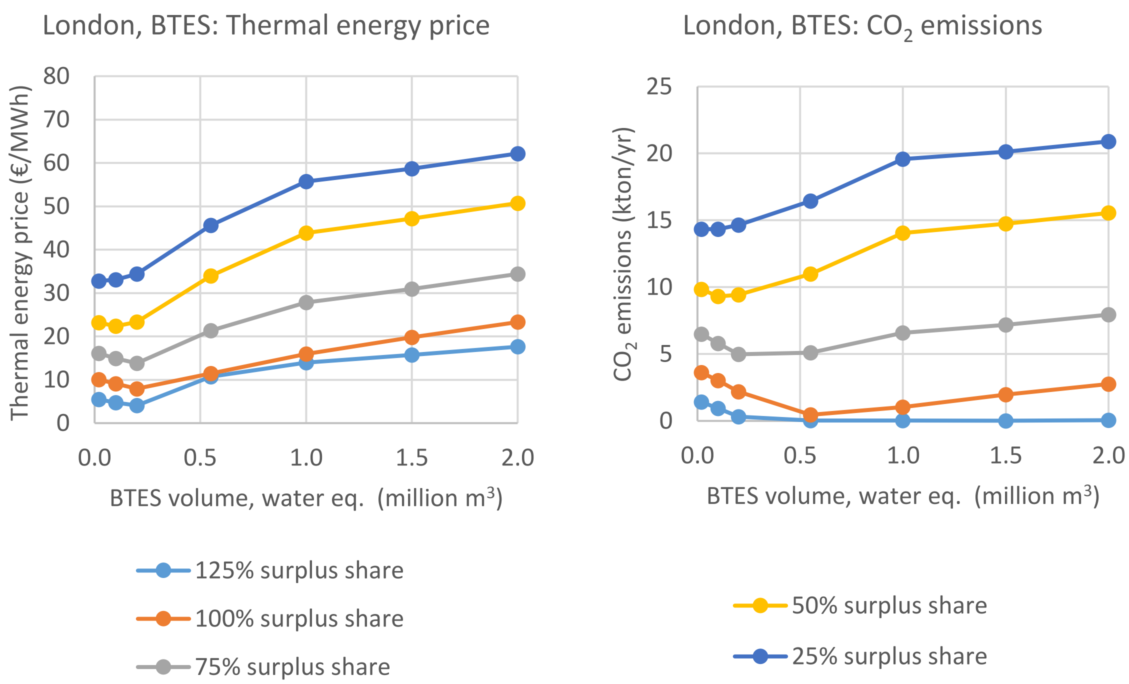

Figure 64 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

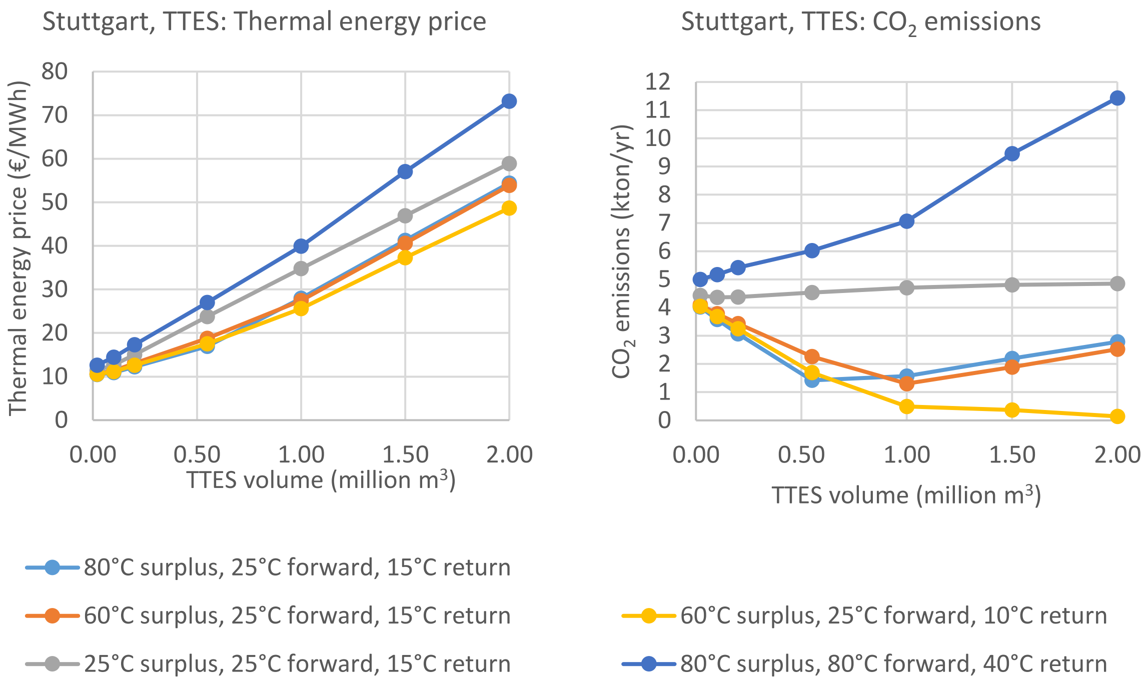

Figure 65 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%.

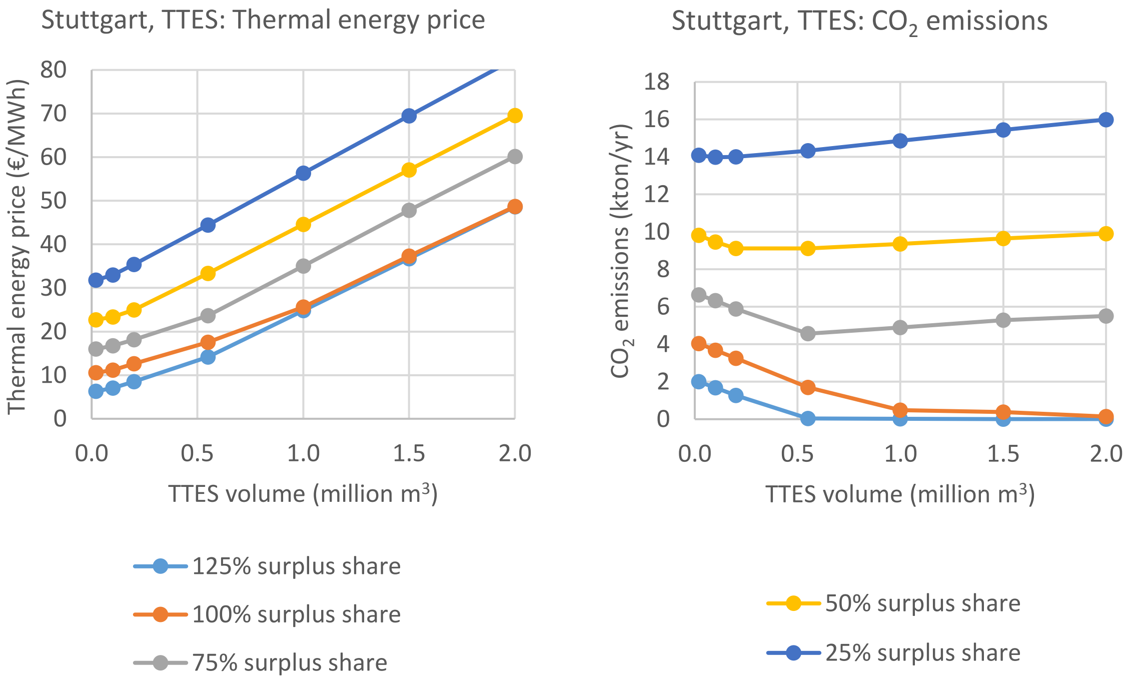

Figure 66 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

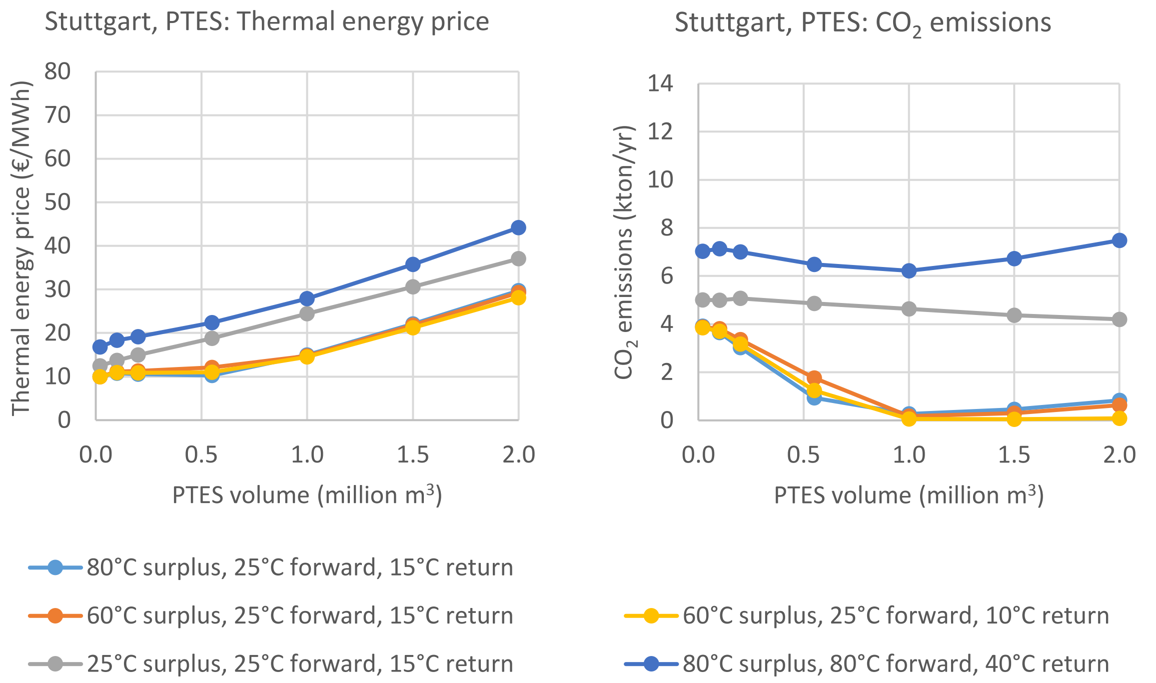

Figure 67 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%. For the largest storage volumes, the blue, orange and yellow curves are almost identical.

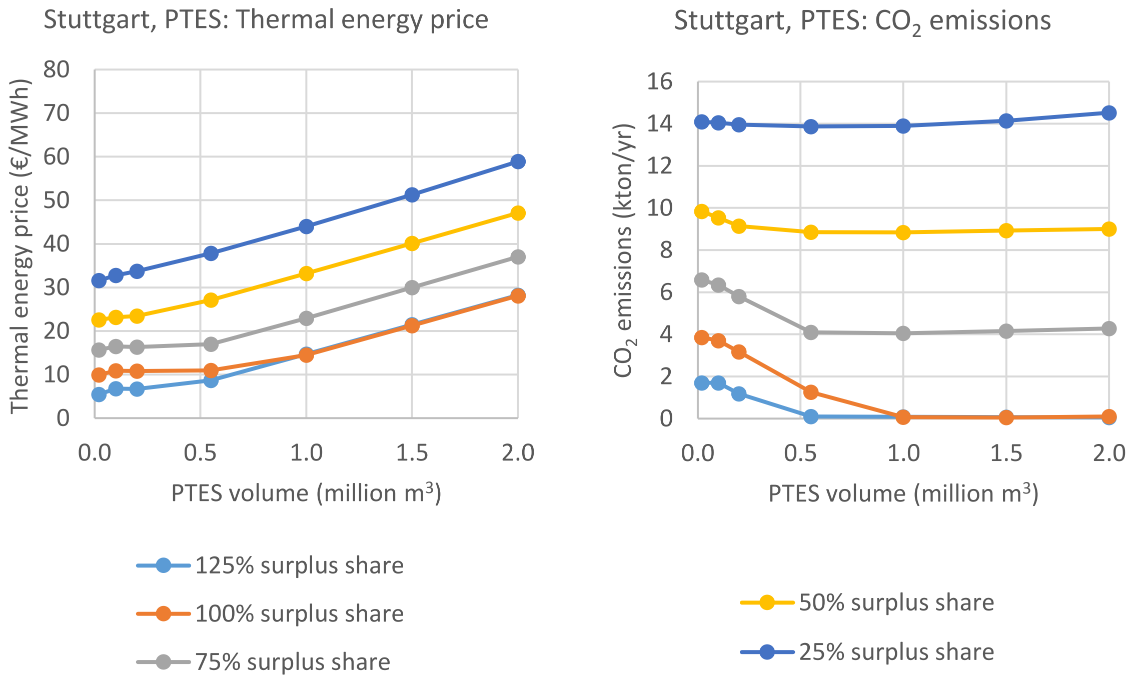

Figure 68 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

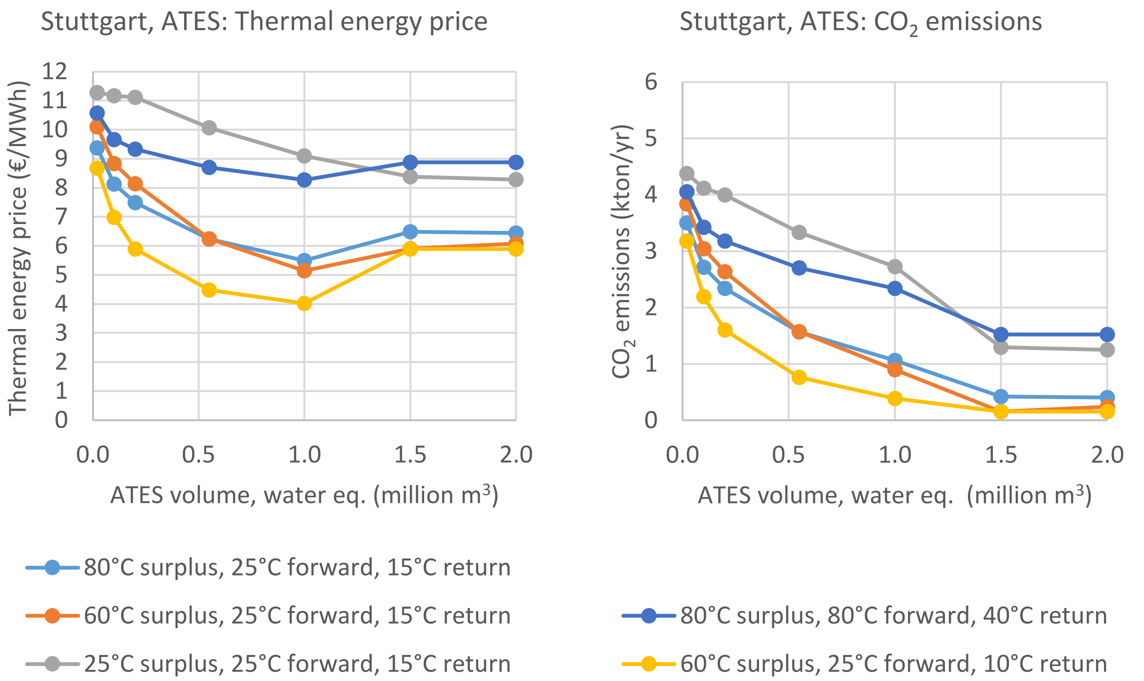

Figure 69 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%.

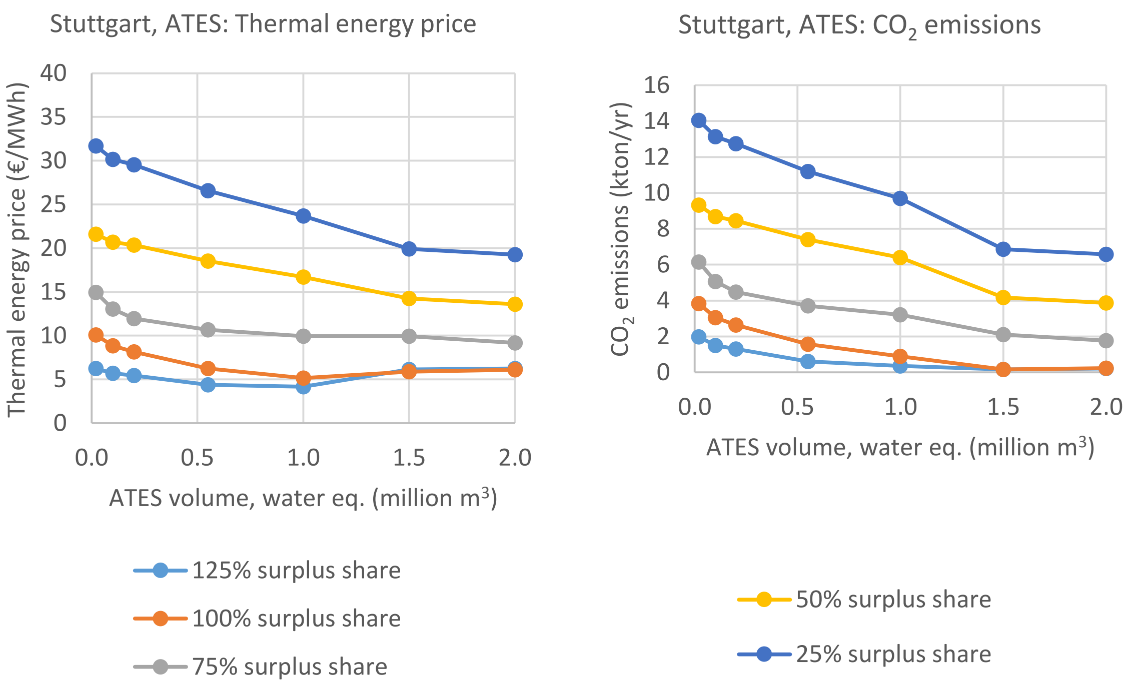

Figure 70 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

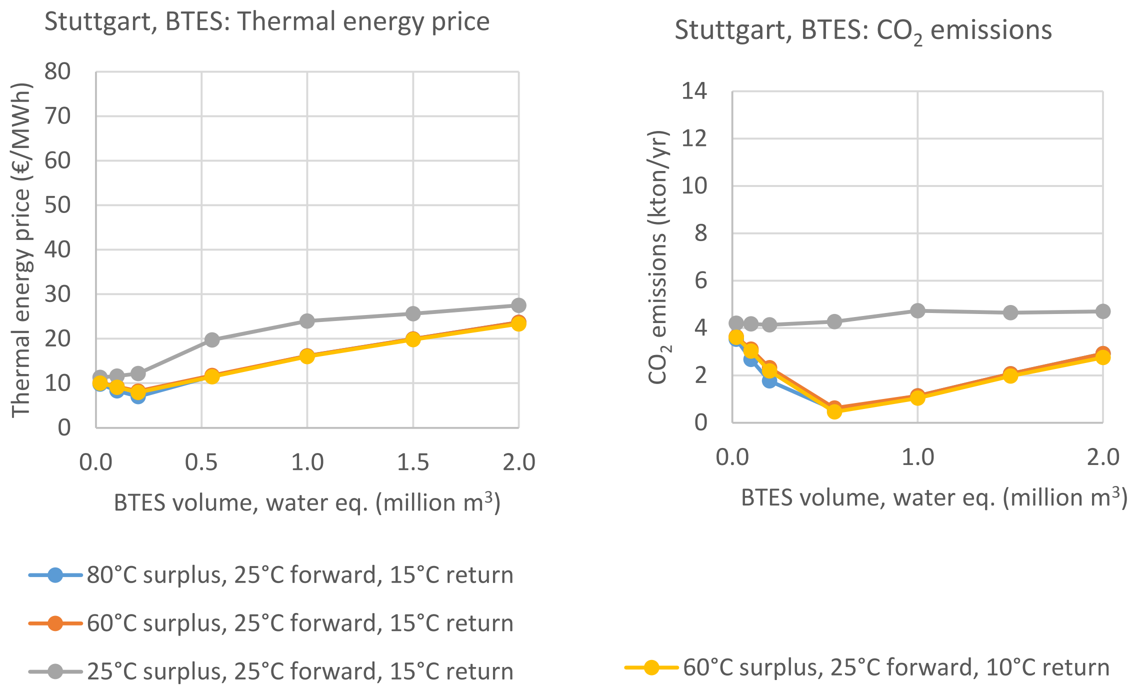

Figure 71 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no surplus heat transmission pipeline is assumed, and the surplus share is assumed to be 100%. For the largest storage volumes, the blue, orange and yellow curves are almost identical.

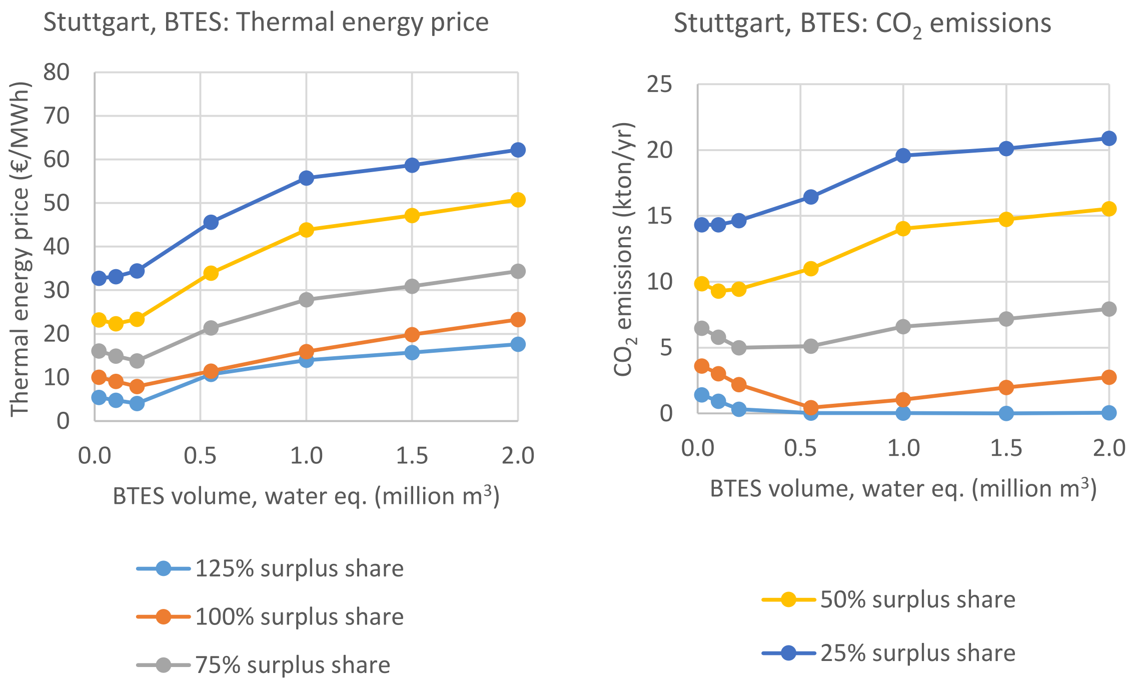

Figure 72 – Left: Thermal energy price. Right: CO_2 emissions. In these calculations, no heat transmission pipeline is assumed. The system is assumed to have a surplus heat temperature of 60 °C, a forward temperature of 25 °C and return temperature of 10 °C.

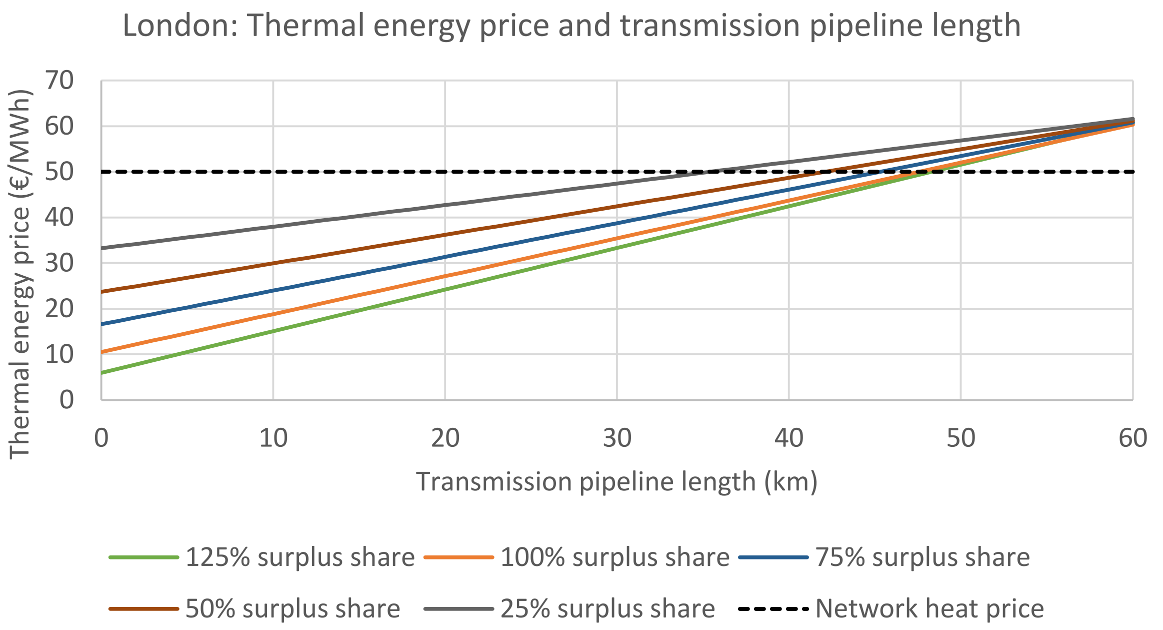

Figure 73 - 100,000 m³ PTES volume, 60 °C surplus, 25 °C forward, 15 °C return. If the network heat price is 50 €/MWh, a transmission pipeline of up to 40 km could be economical in case of 100% or higher surplus heat share.

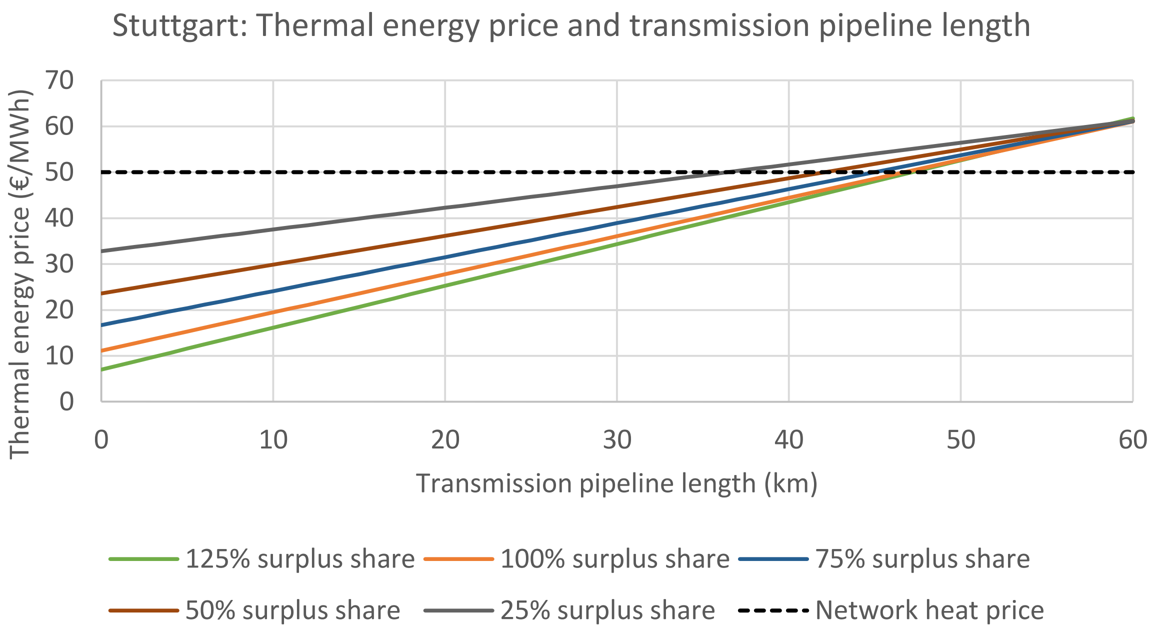

Figure 74 - 100,000 m³ PTES volume, 60 °C surplus, 25 °C forward, 15 °C return. If the network heat price is 50 €/MWh, a transmission pipeline of up to 40 km could be economical in case of 100% or higher surplus heat share.