High Temperature Seasonal Borehole Thermal Energy Storage for Effective Load Shifting and CO_2 Emission Reduction

Robert Weber, Luca Baldini

Urban Energy Systems / Empa, 8600 Dubendorf (Switzerland)

Abstract

A borehole thermal energy storage (BTES) shall be built on the Empa campus. It will be charged with waste heat in summer and discharged with a heat pump in winter. Instead of the currently planned low temperature BTES, a high temperature BTES with a radial temperature gradient shall be investigated with charging from the center and discharging from the outer ring. The aim is to realize an effective seasonal load shifting and a reduction of the yearly CO_2 emission through optimizing for high coefficients of performance (COP) of the heat pump operation in winter. With the help of TRNSYS, different cases with variation of the operational temperature as well as geometrical and hydraulic parameters were simulated. The electrical consumption assigned to the operation of the BTES was converted into CO_2 emissions with the help of dynamic CO2 emission data available for Switzerland. The results show that with the physical limitations given on the Empa campus and the simplified sampling of the CO_2 data used performance expectations could not be confirmed and a consequent implementation of a high temperature BTES on Empa campus will not be realized.

Keywords: BTES, power to heat, seasonal storage, load shifting, CO_2 emission reduction

1. Introduction

Today, the energy system of the Empa campus relies mainly on fossil fuels and it is the goal to transform the system such that CO_2 emissions can be significantly reduced. Heat and cold production as well as the existing heat distribution network will be re-engineered and transformed in the following years. In future, operational waste heat shall be re-used as far as possible. In addition, renewable energy supply shall be increased with a planned PV capacity of 600 kWp. The new campus' energy system is based on the following four pillars: 1) electrical chillers and heat pumps, 2) seasonal borehole thermal energy storage (BTES), 3) heat distribution network with combined mid-temperature line for heat rejection and space heating, 4) bio-gas boilers for covering peak heat demand and a combined heat and power plant.

In the initial planning, a regular BTES is foreseen as found in many other sites in Switzerland (e.g. ETH Zürich Campus Hoenggerberg, Suurstoffi Rotkreuz, Familienheimgenossenschaft Zürich, etc.) with mean storage temperatures close to the natural soil temperatures. Those BTES are typically coupled with a low temperature heating and cooling network.

From a research perspective more interesting is a BTES with higher mean storage temperatures. We hypothesize that storage temperatures in the range of 40-50°C allow for a more significant load shifting from winter to summer in a power to heat application and eventually for direct heating or at least for operation of the heat pumps with higher COP's. Variable seasonal CO_2 loads of grid electricity (higher in winter and lower in summer) as found in Switzerland and many other countries would consequently lead to lower over-all CO_2 emission for heat and cold use.

In this paper the design of a BTES system with elevated temperatures, tailored to the Empa case, is presented and its performance is compared to a standard BTES system as foreseen in the initial planning.

doi:10.18086/eurosun2018.13.04 Available at http://proceedings.ises.org

2. Case description

Measurements of the campus' heating and cooling loads in 2012 (hourly data) show maximum values of around 4000 and 1500 kW respectively (see Fig. 1). Heating loads are typically high in winter due to the large space heating demand. Cooling loads are naturally more expressed during summer but there is a minimum cooling load of about 300 kW throughout the year for cold supply needed for research purpose. The thermal energy demand of the year 2012 for heating and cooling is 5660 and 2645 MWh respectively.

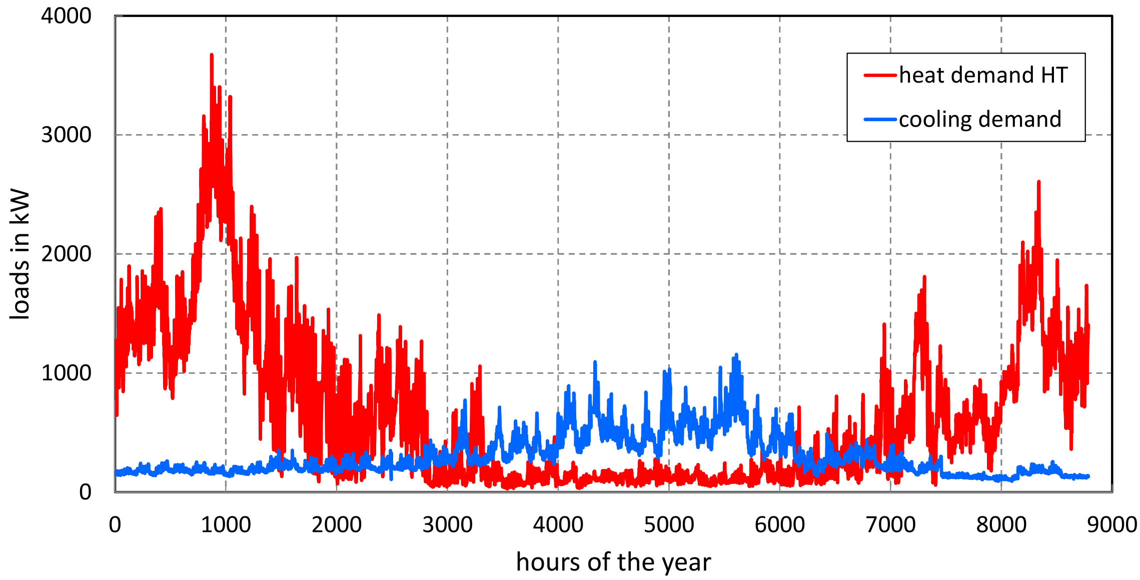
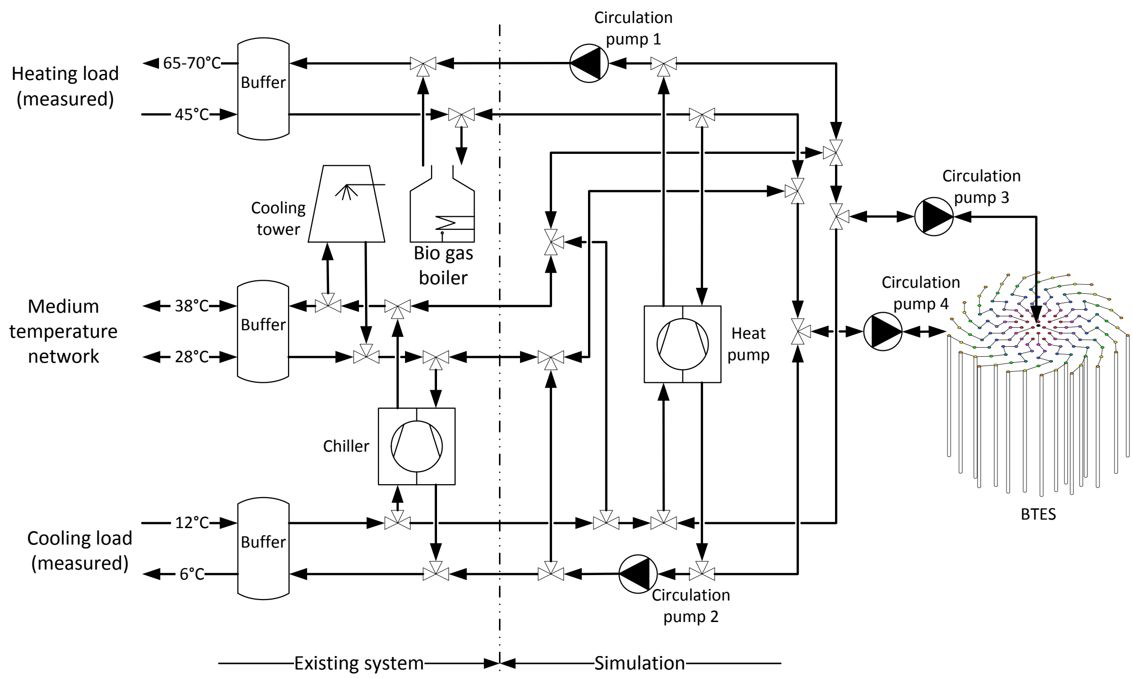


Fig. 1: Hourly heat and cold demand of Empa campus in 2012

The current thermal energy distribution system is based on three networks of different temperatures (see left side of Fig. 2). The heating network uses 65-70/45 °C on the hot/cold side. The former heat rejection network operated at 20/28 °C is in transformation towards an undirected and combined heating and heat rejection network with temperatures of 38/28°C. The cooling network uses temperatures of 6/12°C. The different networks with distinct temperature levels available facilitate the integration of a BTES with temperatures well above the natural soil temperatures.



Robert Weber

Fig. 2: Schematic of the simulated system

The BTES shown on the right side of the hydraulic schematic depicted in Fig. 2 shall be added to the existing energy system and is the subject investigated. As the base energy system of the Empa campus is already built, there are some physical limitations that have to be considered as boundary conditions in the planning phase. The main duct between the central thermal power station and the designated place where the BTES shall be installed already exists. Unfortunately, this duct has limited space and therefore, only two tubes can be placed instead of four as ideally required. This restriction has severe consequences for the performance and hence feasibility of the high temperature gradient storage as will be discussed later.

The heat stored to or used from the BTES is the difference between the hourly heat and cold demand. As Fig. 1 shows, there is also heat demand in summer as well as a cold demand in winter. This simultaneous heating/cooling demand is covered directly by the heat pump, delivering cold and heat to the according buffer tanks. This means that from the yearly 2645 MWh cooling demand, 1270 MWh can be delivered directly and the waste heat produced thereby does not need to be stored in the BTES.

The maximum power with which heat can be stored in the BTES is limited by the cumulated length of the ground heat exchanger (GHX) and the temperature difference of the brine inlet temperature and the ground temperature. To guarantee the operation of Empa's cooling infrastructure during peak hours, beside the BTES, a cooling tower is installed. In winter the heat load beyond the one covered by heat pumps, is covered by a gas boiler.

For the BTES, three different fields where investigated (Fig. 3). All BTES fields where equipped with 144 GHX, with 40mm double U tubing, 102 meter deep and thermally insulated on the top two metres.

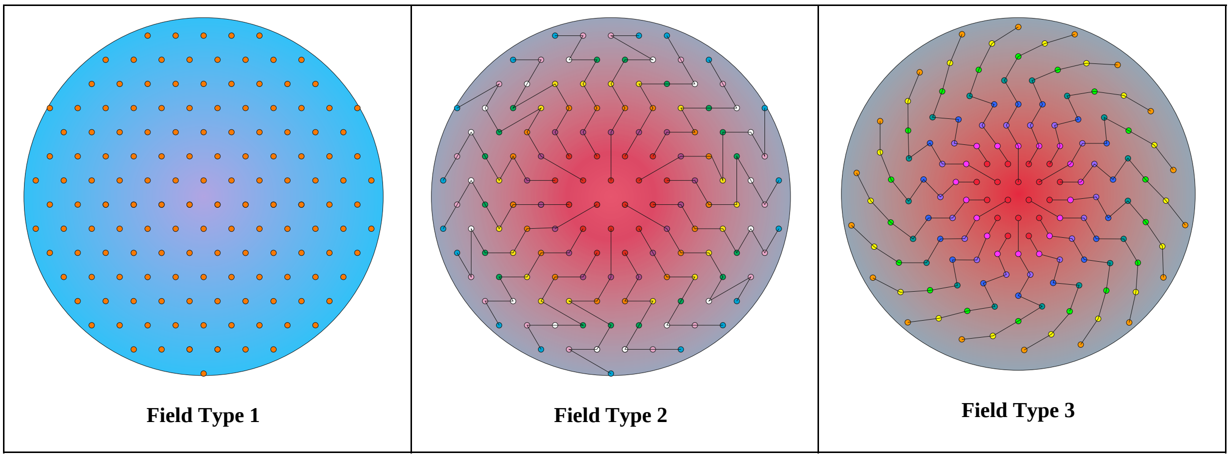


Fig. 3: Three different Types of BTES fields were investigated

Field type 1 is a conventional type of a BTES with parallel feed (144x1) of the brine. This field is equipped with PE-100 tubes; therefore the maximum inlet temperature allowed is 40°C. The minimal outlet temperature in winter is limited to -6°C, in order to have a high temperature range between summer and winter. This requires frost protection and ethylene glycol is added to the brine. This field type is simulated as there is a similar field proposed to Empa and serves as a reference case. Two versions of the field are simulated with two different borehole distances: 4m and 4.5m respectively.

Field type 2 is a BTES where the GHXs are arranged in 18 parallel strings with 8 GHXs in series (18x8). The field is equipped with PEX tubes, therefore input temperatures up to 90°C are allowed. Hot water is feed in the center and cold water on the periphery. The distance between the boreholes is always 4m, but there are different combinations of maximum inlet temperatures and minimal outlet temperatures simulated. Pure water is recirculated as minimum temperatures will always be above the freezing point of water.

Field type 3 is a BTES where the GHXs are again arranged in18 parallel strings with 8 GHX in series. Also this field is equipped with PEX tubes. The difference to field type 2 is the varying distances between the boreholes. In the center, the borehole distance is 3m, on the periphery, the distance increases to 4.5 m. Also this field is simulated with different combinations of maximum inlet temperatures and minimal outlet temperatures and pure water without anti-freeze.

Tab. 1: Cases simulated

Simulation cases	BTES field type	BTES field diameter [m]	Distance between GHX [m]	Hydraulic	Inlet temperature charging [°C]	Min. ground temperature discharging [°C]
Par_4m	1	48	4	144x1	38	6
Par_45m	1	54	4.5	144x1	38	6
Ser_4m_55_15	2	48	4	18x8	55	15
Ser_4m_55_20	2	48	4	18x8	55	20
Ser_4m_60_20	2	48	4	18x8	60	20
Ser_4m_65_15	2	48	4	18x8	65	15
Ser_4m_65_20	2	48	4	18x8	65	20
Ser_4m_65_25	2	48	4	18x8	65	25
Ser_4m_65_30	2	48	4	18x8	65	30
Ser_4m_70_20	2	48	4	18x8	70	20
Grad_345m_55_15	3	47	3 – 4.5	18x8	55	15
Grad_345m_55_20	3	47	3 – 4.5	18x8	55	20
Grad_345m_60_20	3	47	3 – 4.5	18x8	60	20
Grad_345m_65_15	3	47	3 – 4.5	18x8	65	15
Grad_345m_65_20	3	47	3 – 4.5	18x8	65	20
Grad_345m_65_25	3	47	3 – 4.5	18x8	65	25
Grad_345m_65_30	3	47	3 – 4.5	18x8	65	30
Grad_345m_70_20	3	47	3 – 4.5	18x8	70	20

3. Methods

Simulations performed to study the storage behavior and over-all system performance is done with TRNSYS 17.1 (2016). The BTES is simulated with an unreleased TRNSYS TYPE based on the TRNSBM (Pahud et al., 1996). This TYPE allows for almost any combination of hydraulic connections between the boreholes and offers the flexibility needed for performance optimization. The theoretical foundation of the simulation model used is the g-function method introduced by (Eskilson, 1986).

For the heat pump, a compressor driven system with the refrigerant R717 (ammonia) was assumed. For the simulation a constant electrical power of 150 kWe was chosen and for partial load on/off operation was used to meet the actual heating/cooling demand. The COP of the heat pump was calculated with a regression according to the diagram in (Sigrist, 2010):

$$COP = 0.6 \cdot \frac{T_{hot}+3.0}{T_{hot}+3.0-T_{low}-2.0} \quad \text{(eq. 1)}$$

Different BTES inlet temperatures in summer (charging) were assumed (see Tab. 1). To reach high inlet temperatures in the BTES fields 2 & 3, the according mass flow had to be reduced, as the heat pump has limited power. This leads to the desired temperature gradient over GHXs which are configured in series. It was checked that the mass flow always allowed for turbulent flow and adequate heat transfer.

The inlet temperature in winter (discharging) was calculated as:

$$T_{in,BTES} = Max\left(T_{Min,cold}, T_{out,BTES} - T_{cold,diff}\right) \qquad \text{(eq. 2)}$$

with a minimum temperature $T_{Min,cold}$ = 4°C for the serial cases and -9°C for the parallel cases and temperature differences $T_{cold,diff}$ of 15K for the serial cases and 3K for the parallel cases. The mass flow was adapted accordingly. Discharging is stopped when the BTES outlet temperature $T_{out,BTES}$ of the preceding hour fell below the min. ground temperature (see Tab. 1).

Either of the circulation pumps 1 & 2 (see Fig. 2) is considered to have a nominal electric load of 3kW, when the heat pump was on and cold or heat was delivered to a buffer tank. The actual electrical consumption of the circulation pumps 3 or 4 was calculated according to eq. 2 with η = 0.65:

$$P = \dot{m} \cdot (0.790 \cdot ln(Re) - 1.64)^{-2} \cdot \frac{\rho_{brine}}{2 \cdot d} \cdot L_{tube} \cdot \eta \qquad \text{(eq. 2)}$$

The initial idea of the study was to reduce the yearly CO_2 emission of Empa's energy supply. Fig. 4 shows, that the CO_2 emission of the Swiss electric grid in summer is highly reduced in comparison to winter. (http://www.electricitymap.org). As the measured energy demand of Empa and the CO_2 Intensity are not from the same year, in the simulation, a regression is used to calculate the hourly CO_2 demand (Fig. 4).

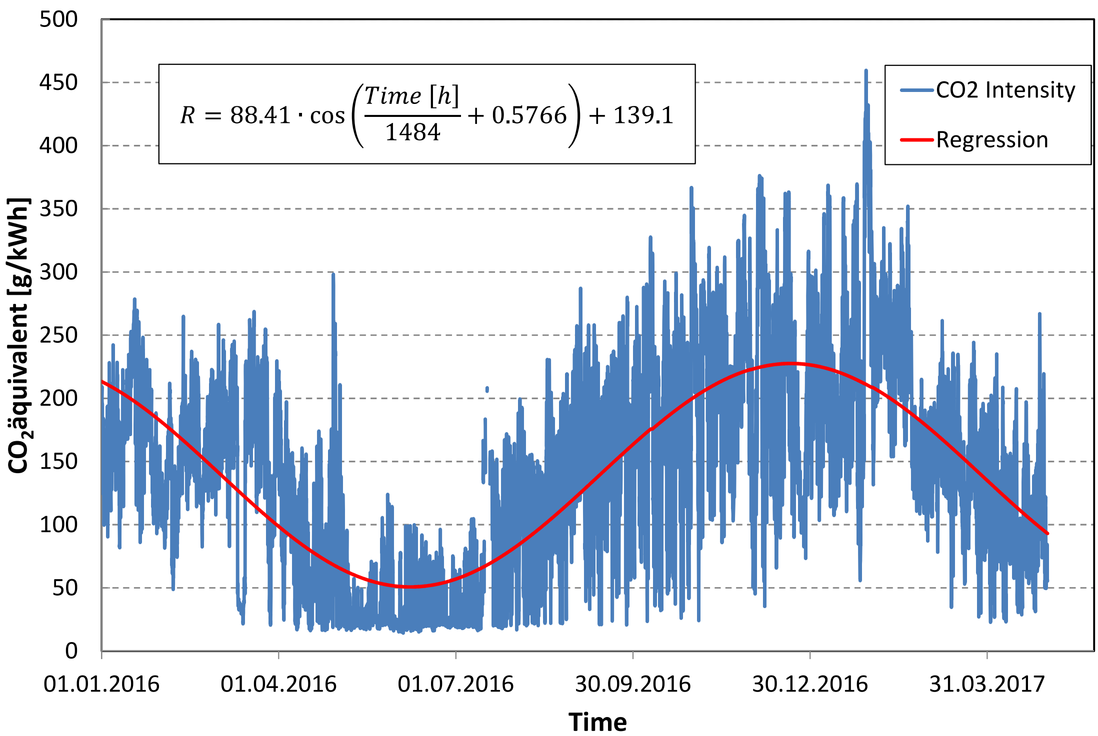


Fig. 4: A regression for dynamic CO_2 emissions (embodied energy included) was calculated using data from (http://www.electricitymap.org)

The operating strategy for the simulation in summer (cooling demand higher than heating demand) is divided into three steps:

1. Cooling demand is covered by the heat pump as far as possible whereby waste heat produced is being rejected to the high temperature heating network to directly cover heating demand.
2. For additional cooling demand chillers are being operated, rejecting their heat to the medium temperature network in the parallel BTES cases. In the serial BTES cases heat from heat pump operation between cooling and high temperature network is used to charge the storage.
3. Surplus waste heat, which can't be delivered to the BTES is cooled away with a cooling tower (typically necessary in case of peak cooling demand).

In winter, the operating strategy for heating (heating demand higher than cooling demand) is also divided into three steps:

1. The central heat pump is operated to satisfy the cooling demand taking heat from the cooling network and rejecting to the high temperature heating network.
2. Additional heat is delivered to the high temperature heating network by the heat pump while discharging the BTES.
3. Peak heat demand, which cannot be covered by the BTES and the heat pump is covered by a gas boiler.

4. Results and Discussion

The analysis of simulation results showed that after 10 years of operation ground temperatures were almost steady with reference to former years and hence close to final operating temperatures. Therefore, all results presented are representing year ten of operation.

The following graphs compare the different cases in terms of:

1. absolute waste heat stored in summer (charging the storage)
2. absolute heat delivered in winter to the heat pump to provide heat at 65°C
3. yearly produced CO_2 (excluding contribution from gas boiler)

As already mentioned earlier, the aim of this study is to find a BTES in the frame of Empa's restrictions (no possibility of multiple connections to the BTES) which delivers a high fraction of heat in winter with a very small fraction of CO_2 emitted.

The amount of heat stored in the BTES depends on many factors: on the ground temperature, the GHX length, the distance between the individual GHXs, the inlet temperature during charging, the power of the heat pump, the specific heat and heat transfer coefficient of the ground. The last two factors can't be changed, but they have an influence on the heat loss over a year. In Fig. 6. it can be seen, that for all cases the cooling capacities are higher than the heating capacities. This effect is a consequence of the average storage temperatures being

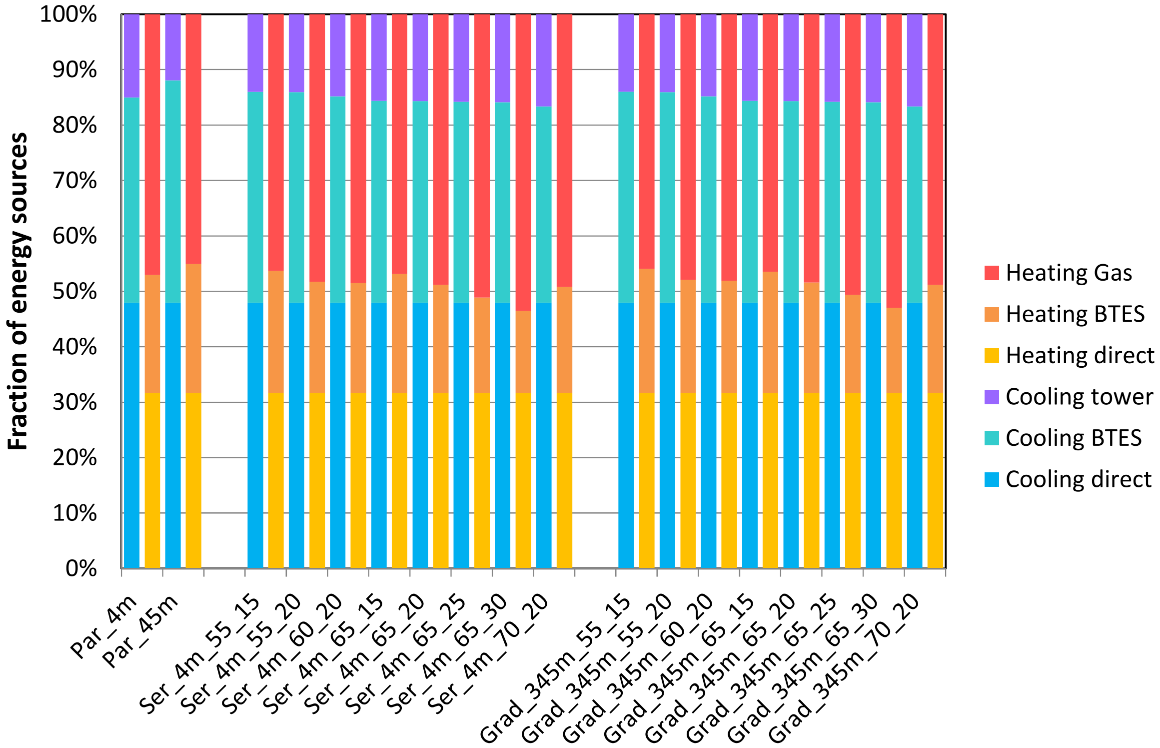


Fig. 5: Sources used to cover cooling and heating demand

higher than the undisturbed surrounding ground temperature. This leads to a permanent heat loss to the ground and to the atmosphere and hence to a depletion of the storage

Interestingly, the simulation showed that among all cases the fractions of different energy sources used to satisfy the demand are quite similar (Fig. 5). In “heating direct” and “heating BTES” the electrical consumption from the heat pump is included. What one does not see in this representation is the fraction of source energy used by the heat pump to provide the heat, i.e. the COP.

The fraction of direct cooling and heating is constant for all cases, as this is the first step in the above mentioned operating strategy applied within the simulation.

The results from figures 5.-7. show, that differences between field 2 and 3 are very small. However, it can be noticed in figure 6 that field 3, even with just a little lower field diameter shows a slightly higher heating capacity. As this is the only notable difference to field 2, only results of field 2 are further discussed.

Figure 6. shows that the storage capacity of case “Par_45m” for both, cooling and heating are superior to all other cases. One reason for this result is the bigger ground volume involved (+20%). The other reason is the different hydraulic link to the power plant. There is a power limitation for the heat stored in the BTES for all serial cases, as only heat from the heat pump is used. For the parallel cases, waste heat from the chillers is directly used (without involving the heat pump). There, no mass flow limitation exists but the temperature is limited to 38°C. Especially in the early summer, peak cooling loads can be better stored in the parallel flow BTES, whereas peak loads in late summer can be better stored by the serial approach because of higher inlet temperatures available.

The cases with $T_{min, ground}$ = 20°C, seem to show a strange behavior (Fig. 6). The higher the inlet temperature (55°C up to 70°C), the lower the heat stored in the BTES. The reason of that behavior is a constant operation time of the heat pump in summer (for all serial cases) to meet the cooling demand. The heat stored is then dominated by the decreasing COP for higher inlet temperatures, resulting in less heat rejected to the storage.

The influence of the increasing $T_{min, ground}$ can easily be seen in the cases “Ser_4m_65_15” to “Ser_4m_65_30”. The idea of a higher ground temperature was to have a higher COP in winter. Unfortunately, the effect of the heat losses predominates (Fig. 6) finally resulting in higher specific CO_2 emissions (Fig. 7).

The cases “Ser_4m_55_15” and “Ser_4m_65_15” show an unexpected high specific CO_2 emission for the heating case. The reason is the increased mass flow of the brine compared to the other serial cases when the ground temperature comes close to the minimal achievable temperature. As mentioned earlier, the typical temperature difference between BTES inlet and outlet is in the range of 15K. As pure water is being used as heat transfer fluid, the inlet temperature is not allowed to be lower than 4°C. This limitation leads to a significantly higher mass flow which is again resulting in a higher electrical consumption of the circulation pump.

Figure 7. shows the total CO_2 emission per kWh heat or cold delivered per year. The results depend on the CO_2 regression (Fig. 4), the total operation time of the heat pump per year, and the storage capacity of the BTES case. The CO2 emissions of the cooling tower operation and the gas boiler are not included.

As a tendency it can be stated: A high BTES inlet temperature causes a high CO_2 emission in the heating case opposing the initial hypothesis. It is clearly visible, that the cases with the parallel flow (field 1) are best relative to the heat they provide. The parallel cases do not need to operate the heat pump in summer to charge the storage (more efficient chiller operation instead) but they have a higher electrical consumption for heat pump operation in winter (low COP). However compared with all cases, they still have the lowest CO_2 emission for the heating operation.

With surprisingly low emissions comes the cooling case “Ser_4m_65_30”. The reason is the low storage capacity of the field (see Fig. 6). This reduces the total operating hours of the heat pump in winter and with that, the emissivity over the whole year becomes small. As the charging energy still is in the range of the other cooling cases, the relative emissivity also becomes small.

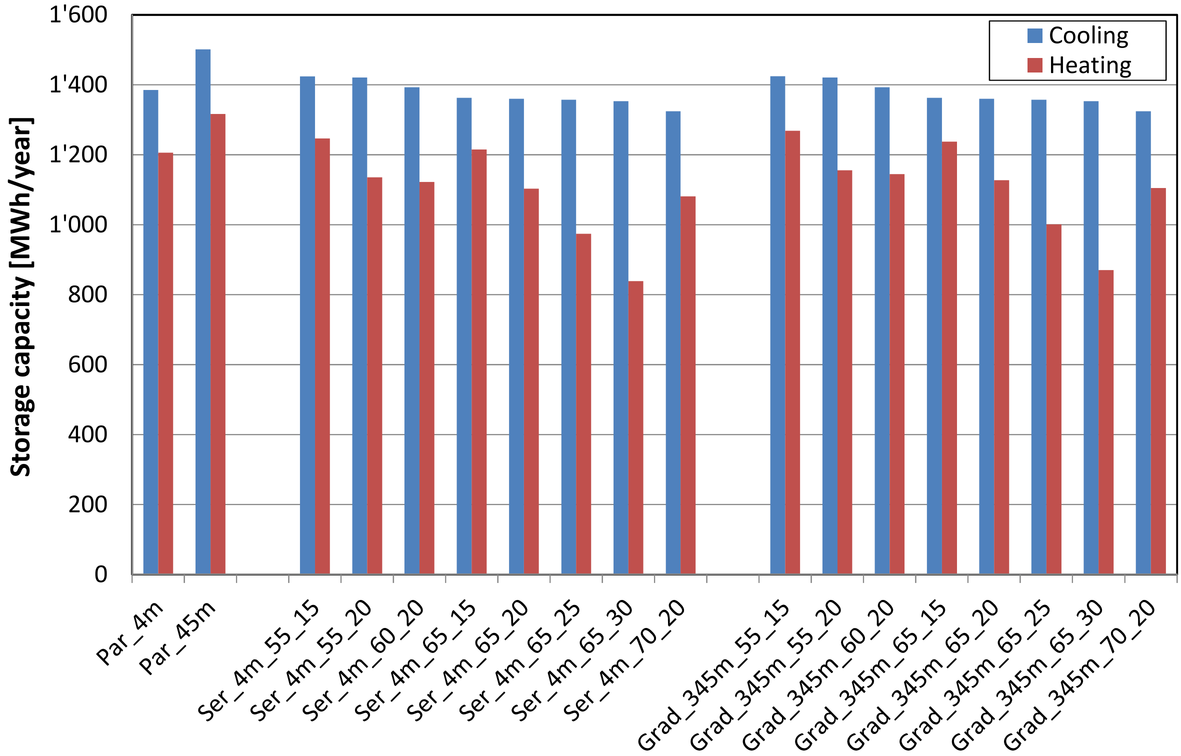


Fig. 6: Total yearly storage capacity under the condition defined

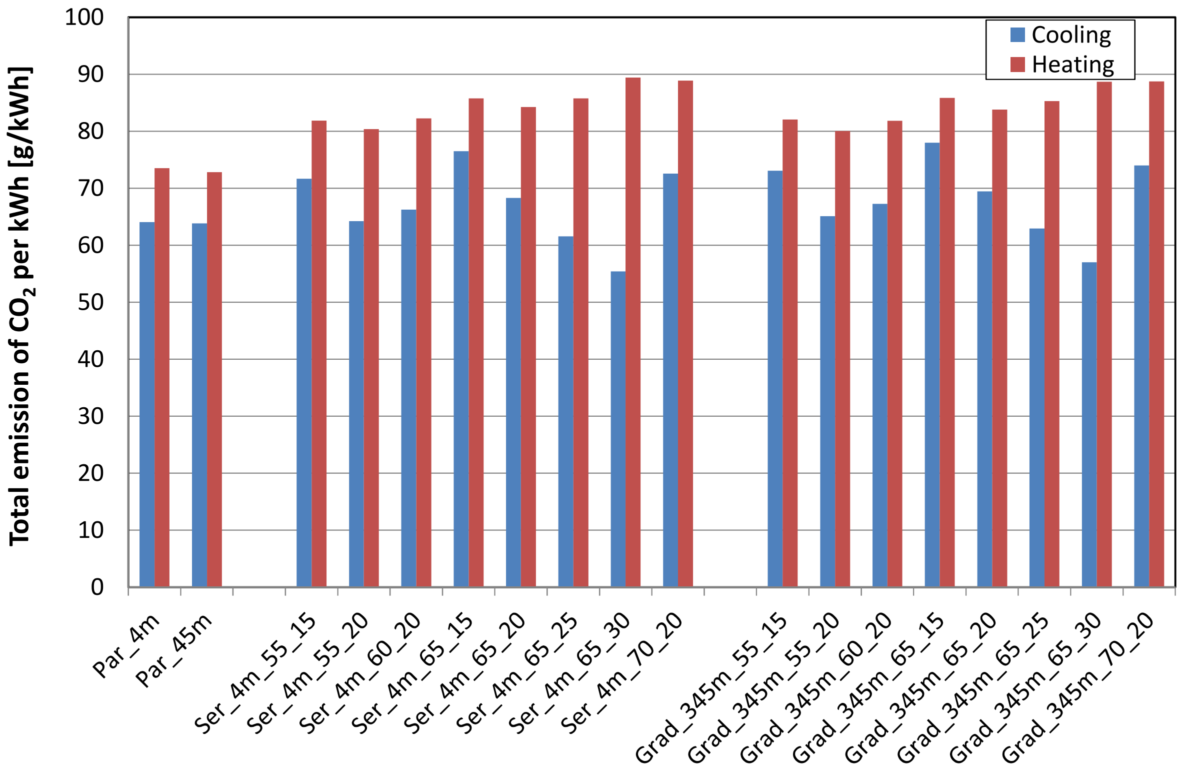


Fig. 7: Total CO_2 emission per kWh heat or cold delivered per year

The initially expected effect on having a BTES system with which excess electricity with low CO_2 loads in summer can be shifted to winter could not be proven with the cases considered. As this is a preliminary study only, not all influencing parameters could be considered properly.

For instance:

- The regression of the CO_2 emissions per kWh is a very rough assumption. Typically, high cooling demand comes along with a high local PV production. This leads to a significant lower emission per kWh electricity than the regression implies. This low value would be beneficial for all cases with high inlet temperatures.
- The original idea for a high temperature BTES was to work with a field with multiple thermal zones. To charge the field, the outer zones would be fed with water from the medium temperature network and the inner zones only with heat of the high temperature network supplied from the heat pump. With that, much lower electricity demand would result for brine circulation and a significantly higher fraction of waste heat could be stored in the field. Unfortunately, this approach needs four tubes to connect the central thermal power station and the BTES, which is not possible at Empa because of spatial limitations in the existing duct.
- To use the thermal energy from the BTES in winter directly in the medium temperature network, the temperature of the BTES was too low. By increasing the temperature, the heat losses to the surrounding ground increase as well. This idea could hence only be implemented in even bigger fields or in fields, where an insulated wall is installed.

As some of the heat and cooling capacities of the simulated serial cases are in the same range as the parallel cases and as there is a possibility that the CO_2 loads of the electricity supplied change considerably, it can be concluded, that there is a chance to find a high temperature BTES solution which clearly shows an electrical grid friendly behavior. Consequently, there is still a chance, that the overall CO_2 emissions as a consequence of above mentioned changes might be reduced compared to a conventional parallel BTES field.

5. Outlook

The simulation study presented revealed a lack of advantage of installing a high temperature BTES at Empa Campus. Physical limitations encountered in this very case though are not considered relevant for the general approach of a high temperature BTES. For this reason, work will be continued and a foreseen approach with borehole fields of larger size and with multiple thermal zones will be further investigated in future.

6. References

1. SEL, University of Wisconsin, Transsolar Stuttgart. TRNSYS 17.1, 2016.
2. Pahud et al., 1996, The superposition borehole model for TRNSYS (TRNSBM), User Manual, Lausanne
3. Eskilson P., 1986, Superposition borehole model, Manual for Computer Code, University of Lund
4. Sigrist T., 2010, GWP mit Kältemittel R717 (Ammoniak NH3), HK-Gebäudetechnik 10-05, 2-5 (German)
5. CO_2 emissions of electricity consumption: http://www.electricitymap.org