Project No. 608930

FP7-SMARTCITIES-2013

OPtimising Hybrid Energy grids

for smart citieS

WP5 Cooperative Control Strategies

Deliverable 5.3.2

Recommendations for control strategies on future use cases

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NEC Europe Ltd.

Version:	1.0
Due Date:	December 31st, 2016
Submission Date:	January 25th, 2017
Lead Coordinator:	NEC

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Deliverable Description

Abstract: This deliverable describes the setup, simulations, control strategies, and simulation results for advanced network hybridization scenarios of the OrPHEuS test site in Ulm, Germany as well as Skellefteå, Sweden.

Key Words: hybrid energy grids , optimization, co-simulation based evaluation, hybrid grid control strategy

Document History

Version	Date	Authors	Description
0.1	2016-06-21	NEC	Document skeleton
0.2	2016-06-24	NEC	Draft of ULM2-space heating description
0.3	2016-06-27	NEC	Improved on ULM2-space heating description
0.4	2016-06-28	NEC	Added details on control strategies and the scenario
0.5	2016-06-29	NEC	Added Ulm-2 scenario description
0.6	2016-06-29	NEC	Added introduction & abstract
0.8	2016-11-30	NEC	Drafts of future scenario and control strategy descriptions
0.10	2016-12-19	NEC	Added SKR-2 description as well, and ulm-2 results
0.11	2016-01-09	NEC	SKR2-results description draft
0.12	2016-01-10	NEC	SKR2-results description completed
0.13	2016-01-13	NEC	improved SKR2 scenario description
0.14	2016-01-16	NEC	conclusion section draft
1.0	2016-01-16	NEC	finalized

Dissemination Level

Dissemination Level		
PU	Public	**X**
PP	Restricted to other programme participants (including the Commission Services)	
RE	Restricted to a group specified by the Consortium (including the Commission Services)	
CO	Confidential, only for members of the consortium (including the Commission Services)	

Executive Summary

The previous deliverable D5.3.1 has presented the project's simulation-based studies of basic hybridization scenarios for the test sites of Ulm and Skellefteå. In this document advanced and more future-looking scenarios for the test sites are studied.

In an extension of the previous present-day scenario for the target site of Ulm, the effects of using photovoltaic surplus energy for space heating are evaluated by simulations of the thermodynamics of individual buildings. Furthermore, a future hybridization scenario based on the assumption of a district heating network at the target site of Ulm is simulated. In these scenarios, the hybridization of energy networks is used to transfer surplus photovoltaic energy from the electricity domain to the heating domain during generation peaks, gaining positive effects on both sides. In addition, a future scenario for the target site of Skellefteå is studied in this deliverable. The present-day scenario from D5.3.1 is enhanced by the addition of an industrial consumer, whose waste heat can be utilized for the heating network of the city, and by a large-scale electric battery helping to mitigate the effects of fluctuating electricity prices.

The simulation results overall demonstrate a positive effect of the hybrid control on the participating grids, but showing also the limitation of some particular approaches like battery storages or conservative storage maintenance policies.

Administrative Overview

Task Description

Task 5.3 *Evaluation of Control Strategies in the Simulation environment* is a highly interactive task that involves WP4 (simulation), WP3 (site data and input), WP2 (economic model and inputs), and WP5 (control strategy). For each *scenario under evaluation*, Task 4.3 provides the co-simulation environment of the target hybrid-grid, where the simulation consumes data from WP3, and Task 2.4 provides the long-term view of each scenario with a social/economic model.

The final evaluation results are contributed toward the holistic evaluation analysis task in WP7. The results are also used in the demonstration work package WP6.

Relation to the Scientific and Technological Objectives

This Deliverable 5.3.2 is directly linked with the following Performance Indicator:

No.	Objective/expected result	Indicator name	STO	Deliverable	MS	Expected Progress		
						Year 1	Year 2	Year 3
16	Validation of Control Strategies with the current and future business models	Control Strategies	STO4	D5.3.2	MS3			1 Due: M30 Draft: M30

It also addresses the STO4 named "Cooperative Control Strategies for cities' Hybrid Energy grids". The key objectives for STO4 addressed in this deliverable are the following:

- De-centralized Control Strategies respecting specifics of individual energy systems and their coupling points while enabling for optimal simultaneous control for multiple grids by designing of Algorithms for Cooperative Control Strategies for Hybrid Energy Networks
- Cooperativeness of Control Strategies and sustainability guarantee for Cooperative Control and Operation

Relations to Activities in the Project

Inputs

- Within WP5: T5.2, control algorithm, which forms optimizer of control implementation.
- From WP3: Sensor / Weather Data relevant for Hybrid grid control.
- From WP2: Economical, price, market information relevant for Hybrid grid control.

Outputs

- To WP7: outputs control evaluation results to holistic analysis for final recommendations.
- To WP4: provides control algorithm and implementation to co-simulation of the target sites.
- To WP2: provides simulation-based evaluation results.
- To WP6: provides simulation based evaluation and report findings to test site partners.
- Within WP5, to T5.4: provides simulation based evaluation results for visualization.

Terminologies

Definitions

Control Setup	A Control Setup is a system view assembled with all physically considered elements (for instance: solar panels, batteries, heat pumps) which are considered in a control space for various use cases. The elements can be controllable or non-controllable.
Control Target	Core goal realizable for a control setup – for instance holistic operation of power-heat network towards profit maximization. This goal can be studied in different use cases which look on certain aspects - for instance: reduce costs considering CO_2 penalties for the heating supplier.
Coupling Point	Physical element which connects two different energy domains (for instance: combined-heat-and-power plant, electric boiler).
Prosumer	Customer enabled to produce energy locally at/near its consumption location.
Use Case	A given goal focusing on a certain stakeholder/market participant under a certain control target - for instance: reduce costs through CO_2 penalties minimizing fossil fuel usage for the heating supplier.

Abbreviations

MS	Milestone
STO	Scientific & Technological Objective
CHP	Combined Heat and Power
PV	Photovoltaic
RES	Renewable Energy Sources
DR	Demand Response
TS	Thermal Storage
EB	Electric Boiler
ESS	Electric Storage System
DSO	Distribution System Operator
DHW	Domestic Hot Water
DH	District Heating

Table of Contents

1 Introduction

1.1 Goal and Scope of the Document

Goal: This document aims to deliver the investigation results of the OrPHEuS hybrid grid control strategies, evaluated within the project's simulation environment. More specifically, the document contains the results from so-called *future* hybrid scenarios for the two target sites (Skellefteå and Ulm), evaluated within the 2nd and 3rd year of the project. The document further reports on an extension of the previous present-day scenario for the target site of Ulm.

Scope: The holistic investigation process employed within the project is a highly interactive activity between WP5 (control strategy development), WP4 (hybrid grid simulation development), and WP2 (economic and business modeling). This document reports on the investigation process and its results from the control strategy perspective.

Self-contained document: The deliverable is mainly written as a self-contained document. It is based on the previous Deliverable 5.3.1 in the sense that the generic investigation process described therein (Section 2) has also been applied in the experiments for the present deliverable. No other OrPHEuS deliverables are required to understand this deliverable. The document uses references to other deliverables and papers, but this is mainly for interested readers who want to follow details of other WPs (e.g. simulation, economic model).

1.2 Composition of the Document

This document begins with two sections about the enhancement of the simulations for the Ulm test site with space heating. First, in Section 2, the scenario, its variations, and the control strategies are described. Section 0 presents the simulation results for that scenario. The two sections thereafter are focused on the future scenario with a heating grid in the Ulm test site. Section 4 presents the details of the scenario, and Section 5 contains the evaluation from our simulations. The future scenario studies for the Skellefteå target site are analogously described in Section 6 and 7. Section 8 concludes this document.

2 Augmented Ulm Present-day Scenario: Space Heating

2.1 Motivation

The previous Deliverable D5.3.1 [1] has reported on the process and results of simulations of a scenario where surplus PV energy is used for domestic hot water systems of local buildings. In that setting, energy from photovoltaic installations can be transformed into thermal energy by means of electric heaters, and stored in thermal storages for later usage as hot water. Technically and economically this approach for local energy storage and usage is attractive because of the technical maturity and high efficiency of electrical heating systems and the low installation and maintenance costs of hot water storages. Furthermore, the demand side of domestic hot water is highly predictable and does not considerably change throughout the seasons.

As described in [1], to investigate the potential of the above hybridization approach we have experimented with various control strategies, various levels of PV penetration in the residential city district under consideration, and with various e-boiler models and heat storage sizes. In the simulations we have monitored a variety of KPIs, ranging from reduction of fossil fuel usage to mitigation of problems in the electricity grid that result from excessive production of photovoltaic energy on sunny days in spring and summer.

From the experiments presented in [1] we concluded that the hybridization approach with domestic hot water is indeed effective. In the simulations we were able to significantly reduce the usage of fossil fuel and at the same time reduce problems in the electricity grid that result from local overproduction of PV energy (like node overvoltage, or energy backflow at the transformer between the low-voltage grid and the medium-voltage network).

While the hybrid combination of PV systems with domestic hot water systems turned out to be beneficial in terms of all KPIs under consideration, our simulations have also demonstrated that not all PV surplus can be consumed by this particular means of hybridization. Especially in summer the PV surplus can be reduced by no more than 20-30%, and therefore problems in the electricity grid remain.

Motivated by this observation, we present in this deliverable the study of an additional variation of the scenario. In this enhanced setting, also space heating systems are enabled to use energy from the electricity grid in situations of local overproduction. The energy demand for space heating is considerably higher than for domestic hot water, and thus it can be expected that the remaining PV surplus can be significantly reduced when there is space heating demand. On the other hand, the demand for space heating is much more dependent on the season than domestic hot water is. Space heating has its peak energy demand in winter, when only little electricity is produced by the PV systems. In summer, when solar irradiation is high, the demand for space heating is close to zero. For these reasons, benefits of this additional energy grid hybridization approach can be expected mainly for the seasons of spring and fall, when solar irradiation is leading to PV energy production and some amount of space heating is required to keep the buildings within their desired temperature range.

Similar to thermal storages for domestic hot water, space heating offers some storage capacity directly in terms of indoor temperature of the houses. Buildings can be heated up to a slightly higher temperature than required when PV surplus is available, and they can be admitted to cool down to a slightly lower temperature at times when there is no surplus to use. This admissible temperature range is determined by thermal comfort zones, that is, temperature ranges within which inhabitants feel comfortable [1].

2.2 Scenario Description

The hybridization scenario we investigate in this section is an enhancement of the scenario for the Ulm test site presented in D5.3.1 [1]. Therefore, many of the descriptions given in this section are summaries of the more detailed specifications that can be found in the respective sections of D5.3.1.

The target site for our simulations is Einsingen, a residential district of the city of Ulm/Germany with a population of 400 inhabitants and 135 houses. What makes this district particularly interesting for our studies is the high level of PV penetration, with 21 panels installed on rooftops, with a peak capacity of 233kW. In addition to the electricity grid, the district has a gas grid which serves as the most common means of heating.

Each of the houses has a heating system for domestic hot water, which is fueled by gas, biomass, electricity, or oil. Furthermore, each house has an electricity demand, while some of the houses also provide electric power from PV systems installed on the roof. The consumers and producers of each building are connected to the low-voltage (LV) power grid, which in turn is connected via a substation to the medium-voltage (MV) network.

What has been described in the preceding paragraph represents the real-life situation in Einsingen, accurately modelled in our simulations taking into account the actual heat and electricity demand profiles as well as the PV generation recorded in 2014. To study the impact of the OrPHEuS hybridization approach, we enhance these models by adding or modifying four kinds of devices.

Firstly, we increase the number and size of photovoltaic panels, which enables us to study the effects of different PV penetration rates, i.e., the proportion of houses having solar panels installed.

Secondly, we equip each building with an electric boiler. These boilers can tap into surplus electrical energy from the local photovoltaic systems to heat up thermal storages that supply domestic hot water. Note that in our simulations the additional e-boilers are installed in all houses, not only in the ones equipped with solar panels, and that they serve as secondary devices installed in addition to the existing fuel boilers. In the design of our control strategies we further assume that these coupling devices have a digital communication interface and thus can be centrally controlled, although not all of our control methods are going to make use of this capability.

Thirdly, we add one water-based storage tank to each house, which can buffer thermal energy to be used as domestic hot water when needed by the residents. For the single family house sector there are no strict regulations, but temperatures above 60°C are recommended for hygienic reasons and comfort. In order to have a flexible buffer for PV surplus, our control strategies can heat above 60°C the storage units using the e-boilers with an upper limit of 90 degree Celsius.

The results presented in the previous Deliverable D5.3.1 [1] are based on simulations of the scenario described up to this point. For the study presented in this document, we additionally add, as a fourth kind of device, electric space heating capabilities in the form of 8kW e-boilers. These devices are added to all houses' central heating systems, except for those buildings that already have night heaters installed, which are designed to charge their thermal storages at night using electricity offered at a discounted price. For our simulations we assume that the night heaters can additionally be charged from surplus PV energy during the day.

To evaluate the effects of electric space heating, we add to our simulations thermal models of the buildings in Einsingen. Space heating can then be performed either by the newly added electric heaters, or by the existing heating systems based on fossil fuels. There are no dedicated fuel heaters for space heating, but the existing devices for domestic hot water are also used to feed thermal energy into the space heating system. It can be controlled at any time whether the fuel heaters are switched off, used for heating up the heat storage for domestic hot water, or used for space heating.

A schematic view of a single house in this scenario is depicted by Figure 1. We remark that for space heating simulations we do not assume the existence of dedicated thermal storages. The buildings themselves are used as storages, as they can be heated up to temperatures higher than required. While the range of *thermal comfort* (admissible temperature range between 20 and 23°C) is only a few Kelvin wide, the thermal capacity of the houses is expected to be large enough to make this storage concept useful.

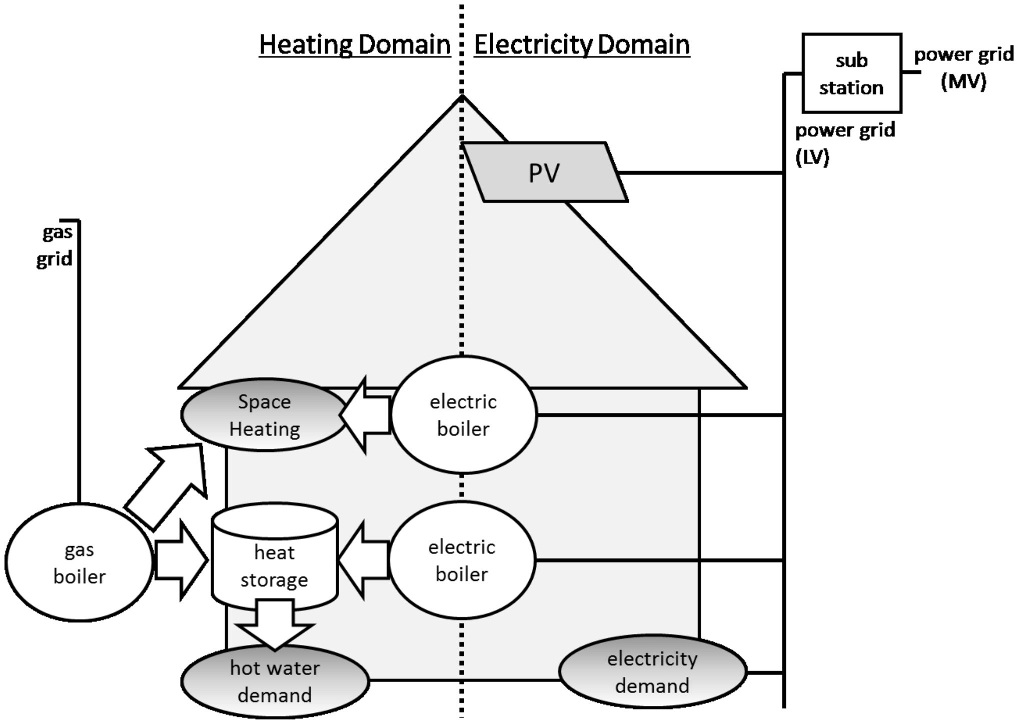

Figure 1: Schematic view of a single house in the Ulm basic scenario enhanced by space heating

2.3 Scenario Variations

In Deliverable D5.3.1 we have studied the performance of a range of e-boilers and heat storage sizes, and we have concluded that the best results are achieved for 2kW boilers and heat storages having a size of 300% of the currently good-practice size in Europe. For the study presented in this deliverable we consider these two parameters to be fixed to these optimal values. Thus, we use a configuration which allows a maximum transfer of energy from the electricity grid to the domestic hot water systems, under the constraint that the energy has to be useful to cover the hot water demand. Whether or not this maximum potential for energy transfer is actually used in the presence of electric space heating capabilities is a question of the control strategy. Note that, for control strategies giving priority to space heating when the available PV surplus is limited, smaller e-boiler sizes and heat storages could potentially be more beneficial for the overall efficiency.

Similarly to the previous experiments without space heating, we consider different **PV penetration** rates, i.e. different assumptions on how many buildings have PV panels installed. In our simulations we use penetration rates of 50% and 75%.

We run simulations using **control strategies** with varying levels of complexity and dependence on communication infrastructure, sensor data, and predictions of demand and supply. The control strategies are described in more details in the subsequent section.

2.4 Control Strategies

The control strategies we are investigating are following a pattern similar to the previous experiments presented in Deliverable D5.3.1 [1], ranging from purely local decisions on the level of individual households to control strategies aiming for global optimization, and taking into account a rich variety of information about the state of the electricity grid and the house temperatures.

Control-1: Local Surplus Usage

What has been denoted as **Control-1** in D5.3.1 is a strategy that involves only households which have PV panels installed. These households use their PV surplus, whenever it occurs, for their own heating demands, greedily charging their heat storages for DHW up to 90°C. In a recent contribution to a scientific conference [2], we refer to this control strategy by the term *surplus-driven control (SDC)*. Nevertheless we continue to use the term Control-1 in the project deliverables for reasons of consistency. In our current scenario, which involves also space heating, a decision potentially needs to me made on whether available surplus is to be used for space heating or for domestic hot water.

Whenever the PV surplus of any house is sufficient to feed both the electric boiler for DHW (2kW) and the electric boiler for space heating (8kW), both devices are switched on if possible (i.e., if the heat storage temperature and room temperature are below the admissible maximum). When the PV surplus is less, Control-1 applies a probabilistic method which has the effect that the *expected* energy consumption of the two heating devices matches the surplus.

To explain this probabilistic strategy, we first assume that at some point in time the hot water storage is already at its maximum temperature, i.e. only the 8kW boiler for space heating can be used, and the available PV surplus at the house is less than that, say 5kW. In that case the available boiler is switched on with probability p = 5kW/8kW = 62.5%, so that the expected value of the energy consumption is p · 8kW = 5kW and thus matches exactly the surplus.

If, under the same assumption regarding the surplus, only the 2kW boiler is available, it is switched on with 100% probability, because the surplus of 5kW is sufficient to power it.

For the case when both boilers are available we introduce a factor **alpha** between 0 and 1, which determines which proportion of the PV surplus is (probabilistically) assigned to space heating, and which proportion is assigned to hot water production. More specifically, hot water receives the proportion of α of the available PV surplus, while space heating is assigned (1-α). In our example, this means that the 2kW boiler for hot water is switched on with probability α ·5kW/2kW, while the 8kW boiler for space heating receives probability (1-α)·5kW/8kW. A simple calculation shows that the expected energy consumption of the two devices again matches exactly the PV surplus. The particular value of α we use is defined as the hot water boiler`s proportion of the energy consumption of both devices, that is, α = 2 kW / (2 kW + 8kW) = 0.2. This choice of α ensures that, from a PV surplus of 10kW or more, the heating devices respectively receive exactly the required 2kW and 8kW, so that both are switched on with probability 100%.

From the viewpoint of the overall district of Einsingen, one can expect from this probabilistic version of Control-1 that the total consumption of the coupling devices matches more closely the total PV surplus. In situations where in most houses the surplus is less than what the coupling devices would consume, some electric boilers will be switched on and some will remain switched off, and this happens without global communication or coordination among the buildings. For the individual houses, however it will happen from time to time that heating devices are switched on which consume more electricity than what the house's PV panel produces. Still switching on the devices with a certain probability can thus be seen as "altruistic" or "social" behavior, and reward mechanisms to encourage such behavior will be needed to make it a reality.

Control-2: Observing the Local Node Voltage

Control-2 (or *Voltage-Driven Control – VDC* in [2]) is also a mostly local strategy, which monitors for each house the electricity node voltage, reacting to overvoltage by switching on the local electric heating systems. The overvoltage threshold is dynamically controlled by a central unit which observes the state of the transformer at the substation and reacts to occurring flow-back by setting lower overvoltage thresholds. In the presence of electric space heating devices one can continue to follow this pattern, heating both the buildings and the DHW storage when local overvoltage is observed.

In the previous deliverable D5.3.1 [1] we have observed no large differences to the central strategy Control-3. Due to simulation time constraints we have therefore decided not to include this strategy in our experiments.

Control-3: Globally Selecting Heating Devices

A more centralized strategy has been studied in D5.3.1 [1] as *Control-3* and called *Reactive Centralized Control (RCC)* in [2]. Here it is assumed that the distribution grid is equipped with Internet-of-Things technology which senses and communicates to the central control module the situation at each node and line of the electricity grid. The control module, which has also full information on the grid topology, switches on a nearby e-boiler for every node overvoltage and line overload it observes, and additionally selects further e-boilers to use until the total power matches the observed flowback at the substation. With the addition of electrical devices for space heating, we have more possibilities to react to grid problems.

At any time step, Control-3 observes the balance between local electricity production and electricity consumption, and whenever the production exceeds consumption the strategy selects a set of electric heating devices to consume the surplus as much as possible. Only heaters whose respective storage capacity (building or hot water storage) are not yet at the maximum admissible temperature are eligible for being selected. The eligible devices are selected based on a priority ranking, which is computed based on the *relative temperature* of the respective storage. This relative temperature is a value between 0 and 1, and is computed as follows.

relative temperature = (current temperature - min) / (max - min), where *min* and *max* represent the minimum and maximum admissible temperatures of the storage, respectively.

As long as there is some remaining surplus, the control strategy selects among the eligible heating devices the one with the lowest relative temperature and switches it on with a probability which is calculated by the ratio between this device's energy consumption (2kW or 8kW) and the remaining surplus. Thus, when this device's power does not fully cover the remaining surplus, the device is switched on with 100% probability, and therefore only the very last selected device obtains a probability of less than that.

Due to this selection mechanism, the expected total power of the selected heating devices matches exactly the surplus whenever enough heating devices are available. However, unlike Control-1, the selection is done by a centralized strategy. In comparison to Control-1, Control-3 also takes into account electric heating devices in buildings having no own PV panels installed.

Control-4: Preserving Storage Capacity for the Irradiation Peak

The control strategies presented so far all follow the *greedy* design principle, as they to try to consume as much PV surplus as possible in any given time step. From the perspective of the heating domain this can be well justified, as it is advisable to fill heat storages at the beginning of the day rather than in the afternoon, so that the stored heat is more likely to be used and less likely to become storage loss. However, from the electric network perspective it is advisable to minimize the peak flowback that occurs over the day. This peak occurs around noon, and when at this time the heat storages are already full the peak remains high regardless of the hybridization.

Control-4 is a variant of Control-3 which delays the full charging of the heat storages until noon has passed. This is achieved by defining a dynamic factor b which is equal to 0 after noon and proportional to the time until noon otherwise. We then execute Control-3 with the additional restriction that, in any time step, only heating devices can be selected whose respective storage has a relative temperature of no more than 1-b. After some initial experimentation we have chosen b = 0.1, so that e.g. one hour before noon the heat storages should not be filled by more than 90%.

3 Augmented Ulm Present-day Scenario: Experimental Results

In this section we present the simulation results for the augmented present-day Ulm scenario, where electric space heating is additionally used as a class of coupling points.

We remark that – in order to be able to simulate more scenario variations within the computational constraints of the simulation hard- and software – we have restricted this set of experiments to the first six months of the year. We have observed before that the second half of the year is essentially symmetric to the first half, and therefore we do not expect to miss any specific insights this limitation of the simulated time period.

3.1 Electricity Network Side

On the electricity network size we first consider the reduction in flowback at the transformer achieved by the hybrid control strategies. Figure 2 visualizes the flowback for the different control strategies and 50% of PV penetration. It turns out that Control-3 and Control-4, which are designed to use all available electric heating devices, are 20-30% more effective in reducing the flowback. It is not surprising that there is hardly any difference between Control-3 and Control-4, because Control-4 is a variation of Control-3 designed to better target the irradiation peaks at noon, but not further reduce the total flowback. The situation for 75% PV penetration is represented in Figure 3, which shows a nearly identical picture.

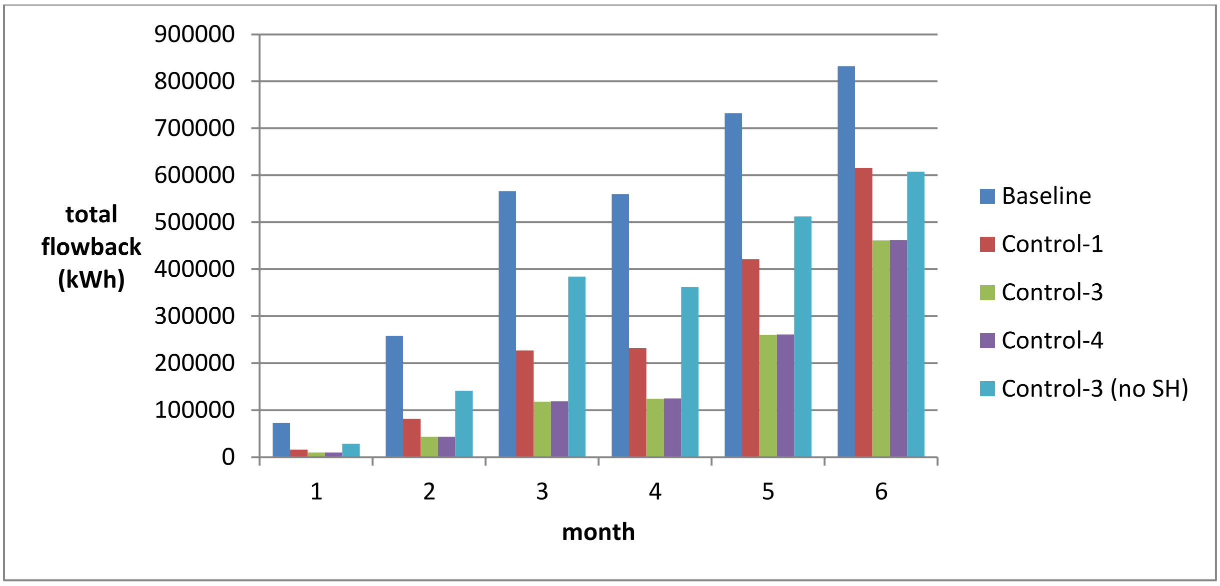

Figure 2: Monthly flowback in the scenario of 50% PV penetration.

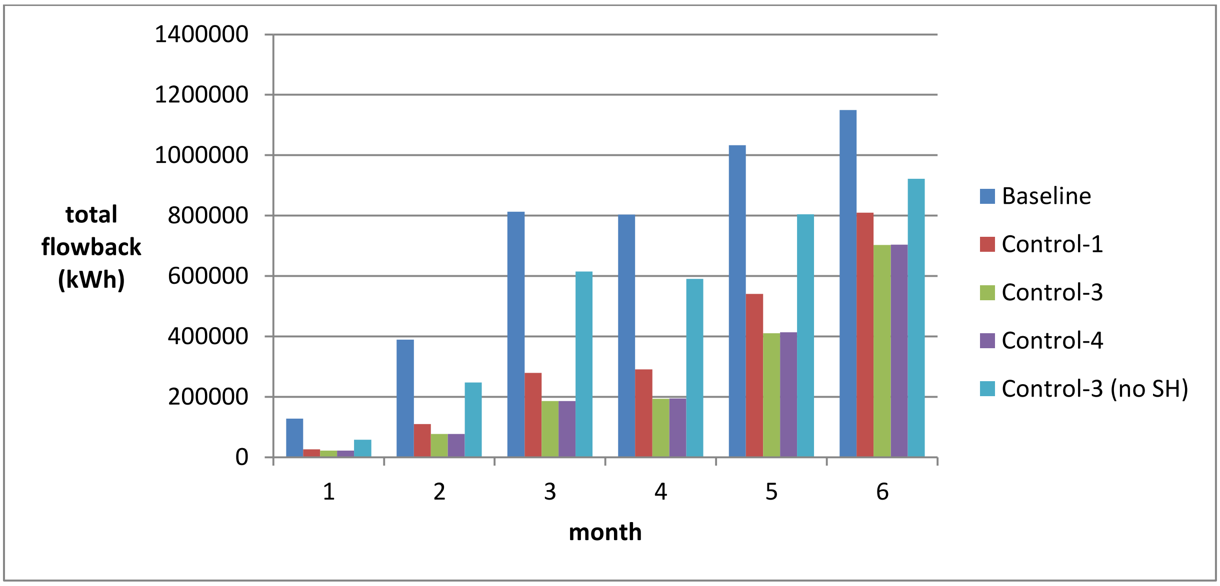

Figure 3: Monthly flowback in the scenario of 75% PV penetration.

For the sake of comparison, Figure 2 and Figure 3 also include the monthly flowback that was observed for the initial Ulm present day scenario where space heating was not included. We restrict our attention to Control-3 described and evaluated in D5.3.1 [2], which was the centralized strategy comparable to Control-3 and Control-4 of the current space heating scenario. The figures confirm that using surplus electric energy additionally for space heating is indeed beneficial as compared to only using it for domestic hot water production. The difference is even visible in the summer months, where still on some cold days space heating is applicable.

One can nicely see that from March onwards the distance between the baseline's flowback (dark blue bars) and the flowback of the control strategy using only domestic hot water (light blue bar) is evenly spaced – an indicator that the usable energy demand of domestic hot water is limited by around 20.000 kWh per month. The additional energy that can be consumed by space heating – represented e.g. by the green bars – has the greatest relative benefit in spring (month 3, 4, 5). This is exactly the period when PV surplus is already available, but there is still enough heating demand to consume much of it.

We next have a look at the ability of the control strategies to reduce the peak flowback, visualized in Figure 4. Here the only remarkable difference between the hybridization approaches is between February and April. This is the time period when it pays off – in terms of this this KPI - to have space heating in addition to domestic hot water coupled with the electricity grid.

None of the three control strategies that include space heating has a clear advantage over the others. This is a negative result especially for Control-4, which was especially designed to save thermal storage capacity for the noon irradiation peak. It is also remarkable that in summer the ability of the control strategies to reduce the peak flowback is very limited. This can be explained by longer periods of high intensity solar irradiations, causing a higher probability of the heat storages being full at some point during the peak. Additionally, space heating plays only a very small role in summer. We omit the figure for PV penetration 75%, as it looks very similar and the conclusions are the same.

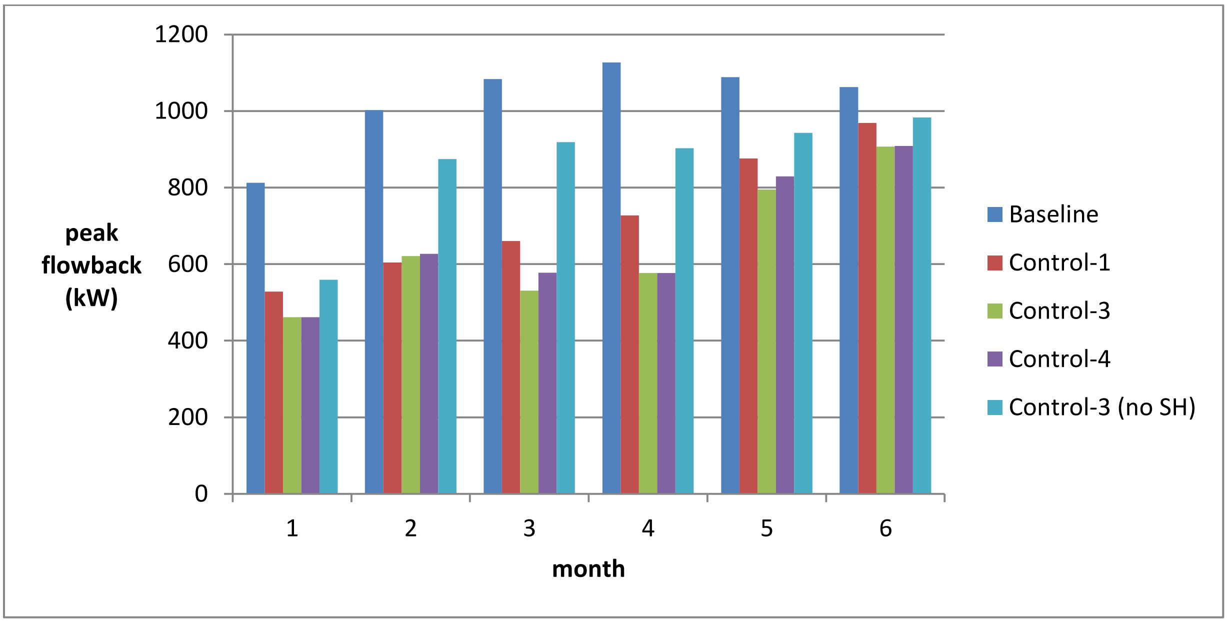

Figure 4: Peak flowback for the scenario of PV penetration 50%.

Figure 5 shows the number of overvoltage incidents for PV penetration 50%. This KPI is exposing a clear additional benefit of space heating coupling points. Control-3 and Control-4 turn out to eliminate nearly all overvoltage situations until May, whereas without space heating at least half of those situations remain from March onwards.

The results for 75% PV penetration are displayed in Figure 6. Here one can see that in the summer months the effects of electric space heating on the electricity grid are much less pronounced than in spring, although some advantage compared to only hot water production remains even in July. Before April the new hybridization still eliminates nearly all overvoltage situations despite the higher PV penetration level.

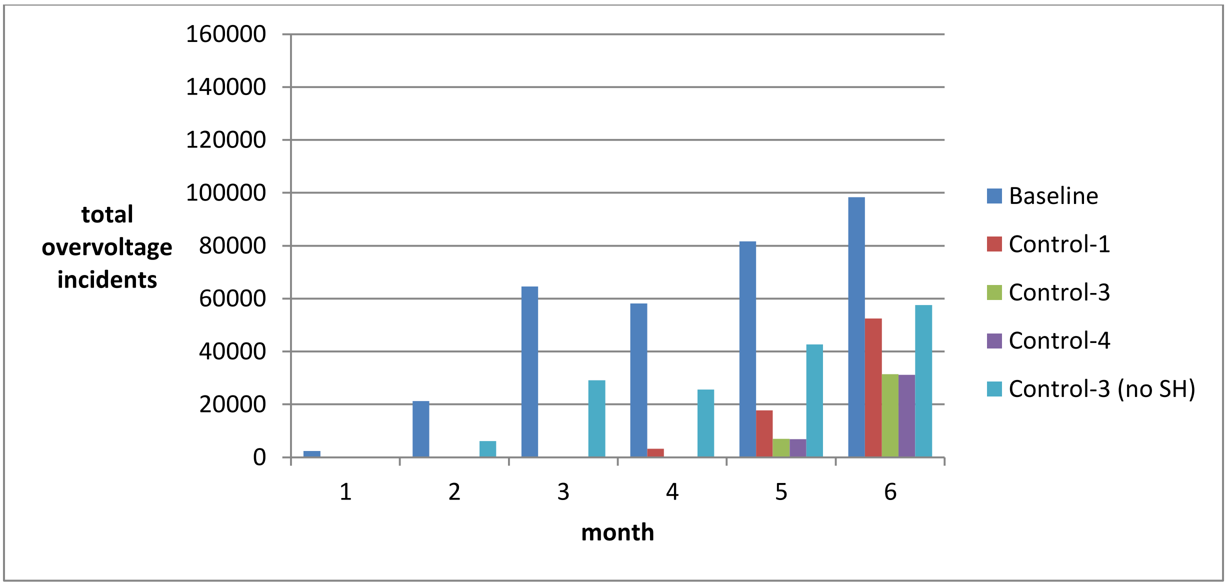

Figure 5: Monthly overvoltage incidents for PV penetration 50%, counted as the number of nodes experiencing overvoltage of more than 105% of the nominal voltage, summed up over all 15-minute time steps.

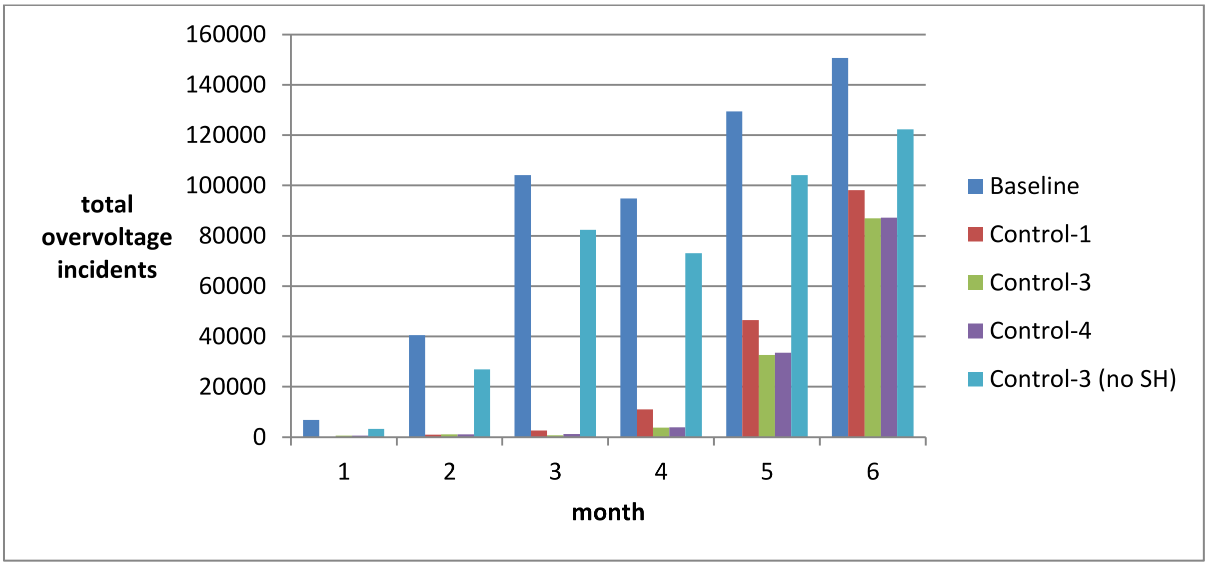

Figure 6: Monthly overvoltage incidents for PV penetration 75%, counted as the number of nodes experiencing overvoltage of more than 105% of the nominal voltage, summed up over all 15-minute time steps.

The monthly numbers of line overload situations are displayed in Figure 7 for 50% PV penetration. All observations about node overvoltage above apply here as well: Space heating does have a positive effect, but in the summer months this effect is much smaller than in spring. We omit the figure on PV penetration 75%, as it contains no additional insights.

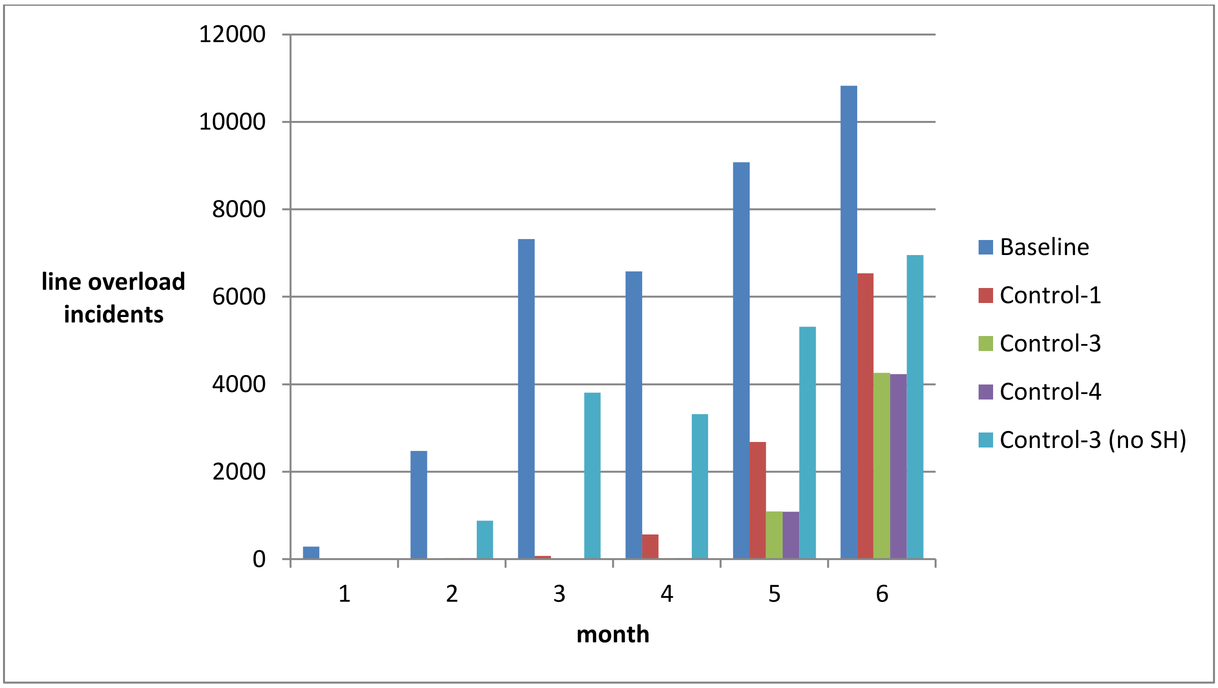

Figure 7: Monthly line overload incidents for PV penetration 50%, counted as the number of lines experiencing overload of more than 105% of the admissible, summed up over all 15-minute time steps.

		Baseline	space heating			no s.h.
			Control-1	Control-3	Control-4	Control-3
node voltage violation incidents	PV 50%	326306	73737	38670	38386	160962
	PV 75%	526385	159720	125870	127745	411999
node voltage violation time (h)	PV 50%	640.75	221.5	131.25	130.75	425
	PV 75%	856.25	343.75	267.5	274	689.5
critical node volt. violation incidents	PV 50%	0	0	0	0	0
	PV 75%	30722	386	382	374	3477
critical node volt. violation time (h)	PV 50%	0	0	0	0	0
	PV 75%	218.75	11.25	8.75	7.5	46.5
line load violation incidents	PV 50%	36572	9870	5402	5382	20288
	PV 75%	56750	18152	14230	14472	44692
line load violation time (h)	PV 50%	603.25	234	138	139.25	435
	PV 75%	841	841	263	267.5	696.25
critical line load violation incidents	PV 50%	17608	2587	1204	1153	5305
	PV 75%	41446	9376	7649	7530	30208
critical line load violation time (h)	PV 50%	395.25	84.75	43.75	41.75	199.5
	PV 75%	704.5	204.75	167.75	168	572.75
transformer load violation time (h)	PV 50%	540.5	123.25	58.25	56.5	279.25
	PV 75%	767	259.75	183	188.75	612.25
Critical transf. load violation time (h)	PV 50%	314.75	35.25	8.5	8.25	56.5
	PV 75%	621.25	136.5	99	96	458
Peak transformer load (%)	PV 50%	135.732	116.806	109.45	109.645	118.553
	PV 75%	185.077	156.451	155.274	155.493	163.97

Table 1: Electricity network KPIs for Ulm present-day scenario with and without space heating, aggregating over the months between January and June.

A summary of the KPIs on the electricity network side with aggregate numbers is given in

Table 1. The numbers show that, when taking into account the whole simulated period of January to June, the advanced hybridization including space heating shows a clear advantage in terms of all KPIs that measure sums. Peak numbers, on the other hand, remain only slightly improved.

3.2 Heating Side

On the heating side, the most important KPIs are the amount of heating fuel saved, and the heat losses. Note that here a direct comparison to the previous scenario without space heating is not possible, because the energy demand and supply of space heating has not been part of the simulation there.

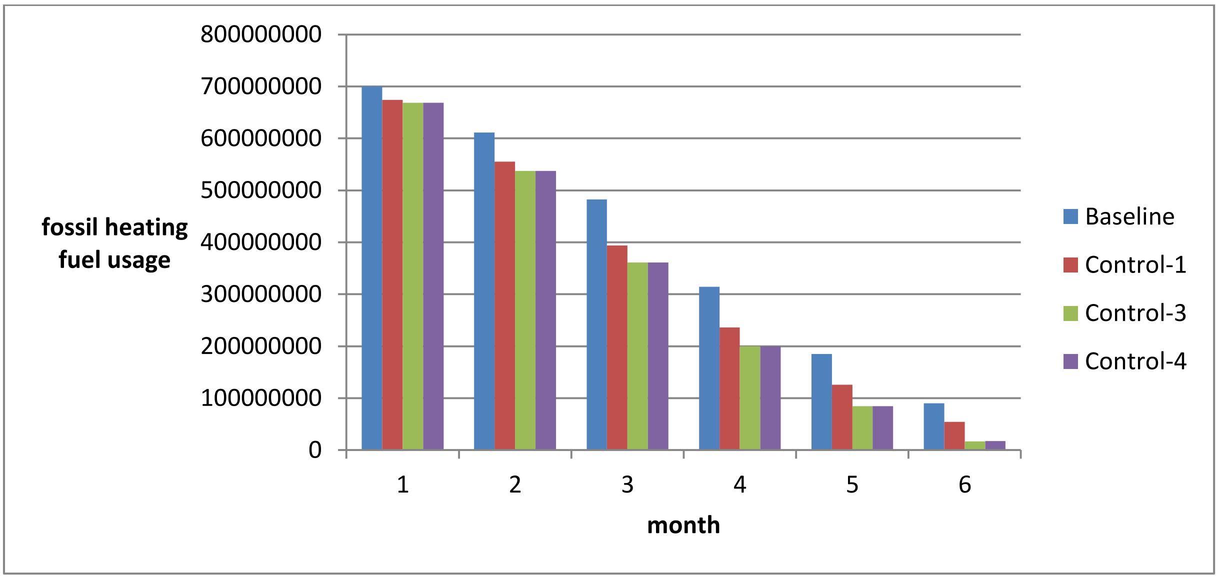

Figure 8: Fossil fuel usage for domestic hot water and space heating in the scenario of PV penetration 50%.

The monthly fossil fuel usage for heating is displayed in Figure 8 (for PV penetration 50%). As expected, the distance between the fuel usage of the non-hybrid baseline (blue bars) and the consumption of the hybrid control strategies is larger in spring and summer than in winter. In May Control-3 and Control-4 turn out reduce the fuel demand by 50%, and in June the remaining fossil fuel demand is less than 20% of the baseline.

Slightly more fossil heating can be avoided in the scenario of PV penetration 75%, as shown in Figure 9. The difference to the PV 50% scenario is the most visible in April, when solar irradiation is already high but still there is enough space heating demand to make use of it.

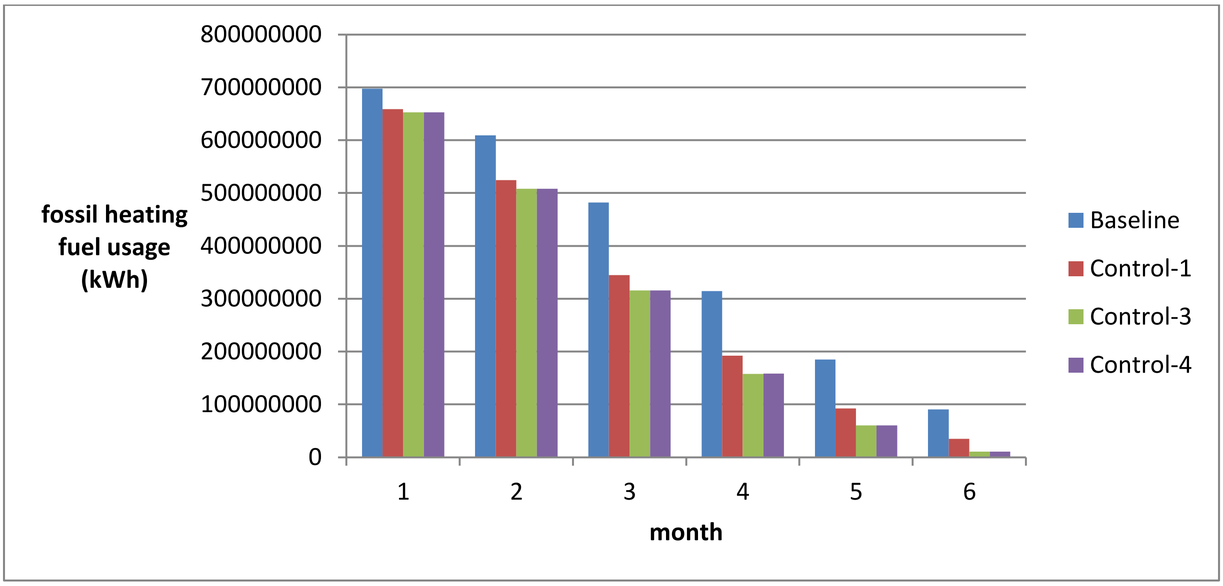

Figure 9: Fossil fuel usage for domestic hot water and space heating in the scenario of PV penetration 75%.

3.3 Results Summary and Conclusions

The experiments have confirmed that space heating represents an attractive additional opportunity for hybridization of energy grids. In terms of most KPIs there is a clearly visibly advantage as compared with only domestic hot water. The only exceptions were the peak values of electricity grid KPIs, and the design approach of Control-4 to keep some storage for the peak while still consuming as much PV surplus as possible has not turned out to be effective. The peak KPIs might benefit from control strategies that are even more tailored towards peak shaving, but this might then come at the expense of the other KPIs.

The centralized strategies Control-3 and Control-4 have outperformed the decentralized Control-1 strategy in terms of all KPIs. This can be explained by Control-1 using only coupling devices in households having PV panels installed and thus not utilizing the whole hybridization potential. A negative result it that Control-4 has not been able to reduce the peak flowback as compared to Control-3. Apparently saving some storage space for the noon irradiation peak is not sufficient, and other approaches are needed.

The amount of sensor readings needed by the centralized control strategies is vastly reduced as compared to the centralized Control-3 strategy that was employed in the previous scenario without space heating. The results suggest that it is sufficient to observe (a) the PV overproduction (which is visible directly at the transformer in terms of flowback) and (b) the heat storage status at each coupling point. Making centralized control read these values and switch on devices to match the current surplus turned out a sufficient level of awareness on the network state.

The simulations have also confirmed the hypothesis that space heating coupling points are most useful in spring. In summer the heating demand is too low, and in winter there is not enough PV surplus to make use of this means of hybridization. We have seen that the total improvement between January and July is still remarkable, but it is a question to economic analyses whether the investment and operational costs are justifiable.

4 Ulm Future Scenario: Feeding Surplus PV Energy into a Heating Grid

4.1 Introduction and Motivation

District heating (DH) grids are rapidly becoming a reality in Europe in general and Germany in particular. Ulm already has an existing DH network serving more than 50% of heat customers and it is therefore important for our partners (SWU and HSU) to study the extension of this network into the district of Einsingen. In addition, such a grid is likely to be a good candidate to absorb some of the PV surplus generated by the prosumer households and thus relieve the electrical grid of the corresponding load.

As described in D5.3.1 and the preceding sections of this deliverable, the previous investigations of Ulm have considered adding e-boilers into individual households to transform electrical PV energy into heat (either for space heating or for domestic hot water). While this has turned out a valuable way to relieve the electrical grid of local issues caused by the surplus, the coupling devices (e-boilers) were rather punctual and did not constitute an interconnected grid. Conversely, simulating a heat district network will fully realize the Orpheus hybrid vision in the sense that both grids will truly benefit from one another: the electrical grid will benefit from a reduction in wear and tear of nodes, lines, and transformers, while the heating grid has the potential to benefit from reduced reliance on fossil heat sources such as gas and oil.

Additionally, more interesting business plans can be considered in this future scenario, addressing the electrical grid operator, the heating grid operator, and the electricity and heat prosumers together. At the moment, indeed, decentralized feed-in of heat into district heating grids is not allowed by the regulations, contrarily to what is happening in electricity grids where prosumers can sell their surplus PV energy. It is conceivable that the same situation will gradually be established for heating networks and we can foresee an urban landscape with locally distributed coupling devices (micro-CHPs, e-boilers, heat pumps, etc.) feeding heat into the district network.

4.2 Investigation Methodology and Setup

The immediate question to answer is the number and nature of coupling devices; shall they be e-boilers, heat-pumps, micro CHPs, and will we need associated heat storage? Micro-CHPs produce and do not consume electric energy, and we preferred to study coupling points which directly transfer energy from the electricity domain into heat. Heat pumps would be an efficient alternative to electric boilers. They represent a different trade-off between investment costs and operational efficiency, and economic studies show that in terms of investment and operational costs electric boilers nowadays still represent a more attractive choice. Furthermore, as we study a scenario involving a large heat pump in the Skellefteå future scenario (see chapters below), we here continue here to use e-boilers similarly to the previous current-day scenario for Ulm.

Heat storages were also deemed necessary as buffers to allow more flexibility. With the help of storages, control strategies can decide when to store heat from PV panels and when to release it into the grid, depending on heat demand, solar irradiation, and predictions of these quantities.

The next point to address is where to install the e-boilers and heat-storages. From a heat district operator point of view, it is cheaper to have a central boiler, whereas a distributed installation of the same total capacity is considerably more expensive, especially when considering installation costs. From the electricity network point of view, a central e-boiler located next to the transformer can mitigate transformer overload and flow-back, but is not expected to mitigate line overload and local overvoltage within the low-voltage network. Due to simulation time constraints we restrict our studies to the centralized e-boiler and storage, but design the control strategies such that they would as well be applicable to the distributed case.

We thus consider two different scenario variations: a baseline with no coupling point and a variant with a centralized coupling point including a large electric boiler and a heat storage.

Baseline: The heat demand of Einsingen is served by the wider Ulm district heating grid, and any PV surplus flows back into the electrical network via the LV-MV transformer. On the electricity grid side this scenario is equivalent to the previous current-day scenario for Ulm.

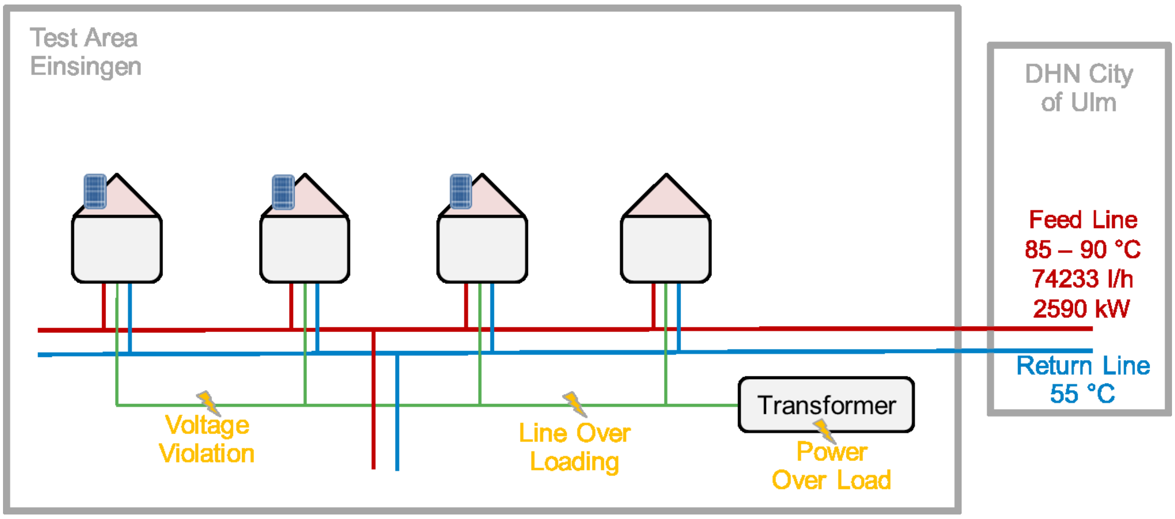

Figure 10: Baseline case for Ulm future scenario.

Central: we are add a central e-boiler and associated heat-storage next to the LV-MV transformer. This e-boiler is powered by PV surplus and is generally allowed to feed heat into the wider Ulm district.

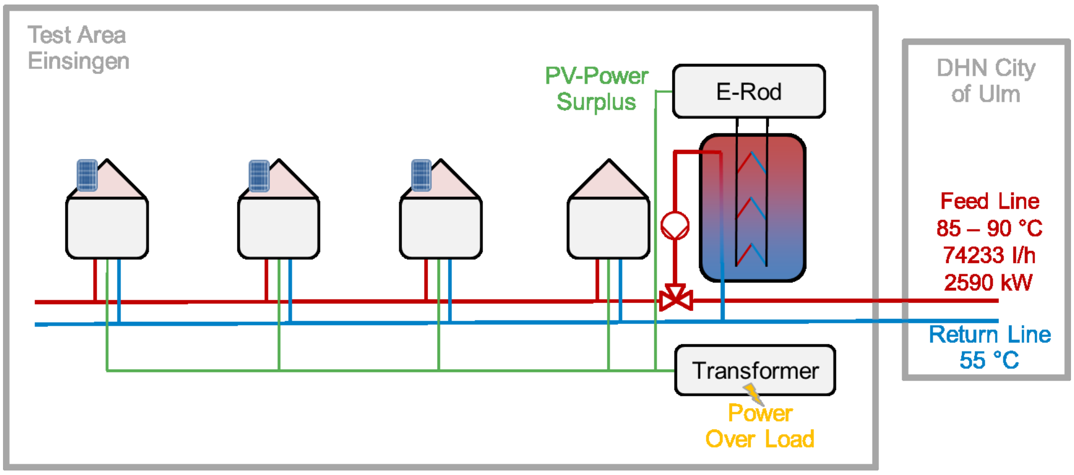

Figure 11: Hybridization of the future scenario by means of an E-boiler and Heat Storage ("E-Rod").

The size of the e-boiler is fixed and based on the maximum PV surplus that is generated on any day in the 75% PV penetration scenario, which corresponds to 6.5 MWh. The size of the e-boiler is configured to absorb 80% of this value, so its maximum power is assigned to 840 kW.

The size of the heat-storage is based on the same maximal daily PV surplus. The heat-storage size simulated will allow taking in 70% of this amount, corresponding to a volume of 135m^3.

The pipeline between the Einsingen district network and the nearest connection to the wider Ulm network has a maximum capacity of 2.6MW. This means that it is able to absorb all the PV-generated heat throughout the year. This pipeline is however 3 km long, which effectuates higher heat losses as compared to local heat-storage appliances.

Additionally, in order to gain insights that are more generally applicable to European cities, we study variations of the scenario where the backflow capacity of the heating pipes between Ulm and Einsingen is limited to a fixed value between 0kW and 500kW. This limitation affects the maximum heat production surplus that the simulated district of Einsingen can generate at any time step. Note that this restriction only applies to energy flow in one direction; the wider ULM district heating network may ways provide as much heat to the households as they require on days where the PV surplus and/or local storage are not enough to satisfy their demand.

4.3 Control Strategies

Control strategies for the previous Ulm current-day scenario were designed to address the challenge of absorbing as much local PV surplus as possible, but taking into account the limited storage capacities and the limited hot water or space heating demand in the households. In case of the future scenario discussed in this section, the problem is relaxed due to the new district heating grid connected to the city of Ulm. Here thermal energy can anytime be exported to the city of Ulm, and thus the heat storages can be emptied whenever required. The only downside of this export is a potential loss of thermal energy in the 3km pipe between Einsingen and Ulm. We are considering two control strategies with different design choices regarding the usage of the heat storages.

Control-A: Maximizing heat export

What we denote with *Control-A* is a strategy which targets to directly export the heat generated from PV surplus. This means that the heat storages are always kept in a discharged state as much as possible. Whenever there is PV generation surplus, the heating power of the e-boiler is set to exactly that surplus as long as the heat storage is not full, which, due to the aggressive heat export policy, is expected to happen only rarely. Of course this control strategy has to respect limitations of thermal energy export to the heating network of Ulm, and therefore the amount of discharging is still limited by the sum of the local heat demand of Einsingen and the maximum heat export value of the particular scenario under consideration.

Control-B: Keeping the storage charged

Control-B is a strategy which is rather focused on keeping heat in the storage for local usage rather than exporting it. This strategy discharges the heat storage only by the amount of the current local heat demand. The only exception is when the heat storage is full; then it is discharged by approximately the value of the current PV surplus, so that the e-boiler can still be operated to consume this surplus. Like Control-A, the e-boiler power is as often as possible set to the current PV surplus. Furthermore, exporting heat is of course limited by the maximum determined by the particular scenario variation under consideration, but due to the conservative discharging policy we expect only a small influence of the maximum export parameter.

4.4 Scenario Variations

We will execute simulations of each scenario variation, where each variation is characterized by the following parameters:

- The physical setup as described above
    - Baseline
    - Central e-boiler and heat storage
- PV penetration
    - 50%
    - 75%
- Limitation of heat overproduction in Einsingen
    - 0kW
    - 100kW
    - 200kW
    - 300kW
    - 400kW
    - 500kW
    - unlimited
- Control strategy
    - Baseline (no e-boiler usage)
    - Control-A (immediate heat release from storage)
    - Control-B (conservative heat release from storage)

5 Ulm Future Scenario: Experimental Results

5.1 Electricity Side

Starting with the variation of PV penetration 50%, we compare the control strategies in terms of how much flowback at the transformer the remaining generation surplus is still causing when the heat export to the heating grid of Ulm is unlimited.

Figure 12 shows that Control-A is better suited to reduce flowback at the transformer, consuming nearly all flowback throughout the year. This is no surprise, as it more aggressively discharges the heat storage and therefore is less likely to have a situation where PV surplus cannot be consumed by the electric boiler.

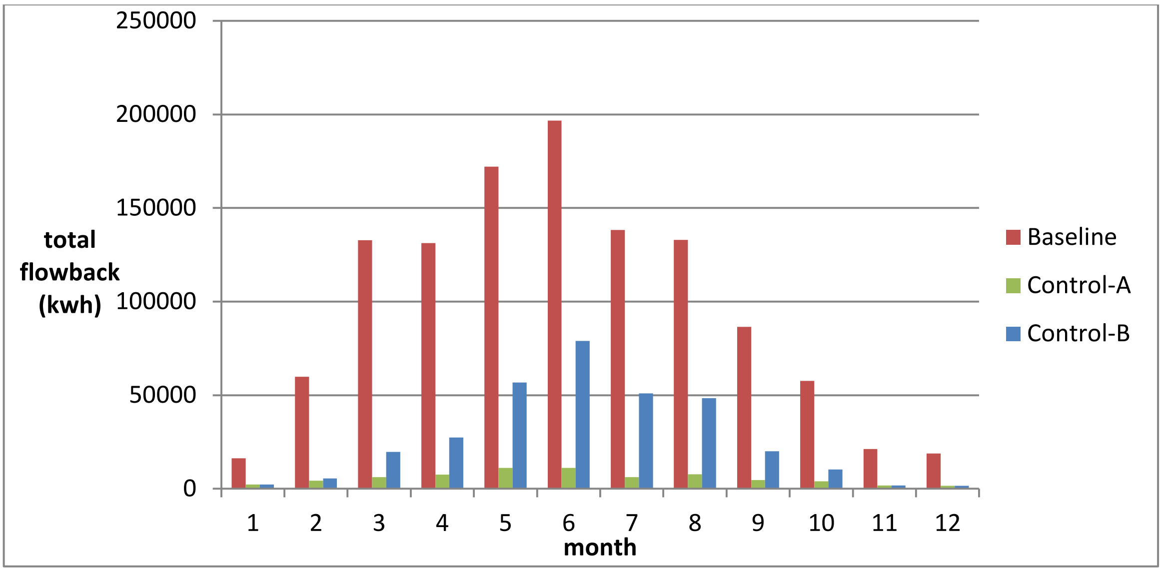

Figure 12: Total flowback at transformer in case of PV penetration of 50% and no limit on the thermal energy export.

Also Control-B is designed so that it exports energy when the heat storage is about to become full, but apparently the storage cannot be charged and discharged as flexibly as foreseen by that strategy; especially in summer.

The picture for PV surplus of 75% looks similar. Figure 13 is does not look exactly like a scaled version of Figure 12; the relative growth of the flowback of Control-A and Control-B is larger than the growth of the baseline. This is an indicator that most of the extra PV surplus of the 75% scenario flows back into the medium voltage grid.

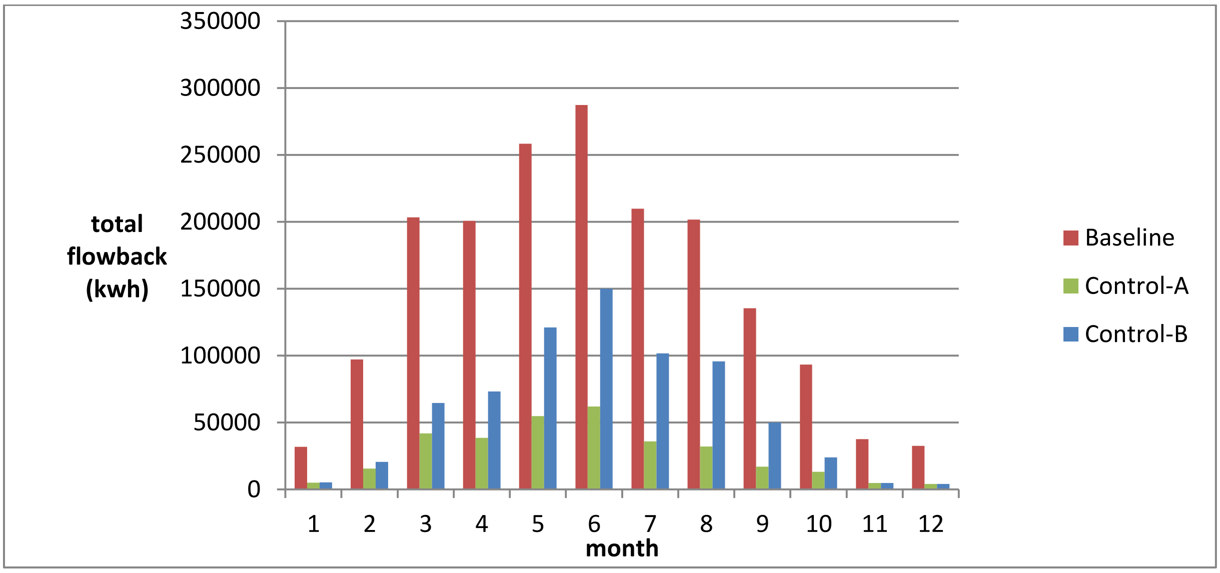

Figure 13: Total flowback at transformer in case of PV penetration of 75% and no limit on the thermal energy export.

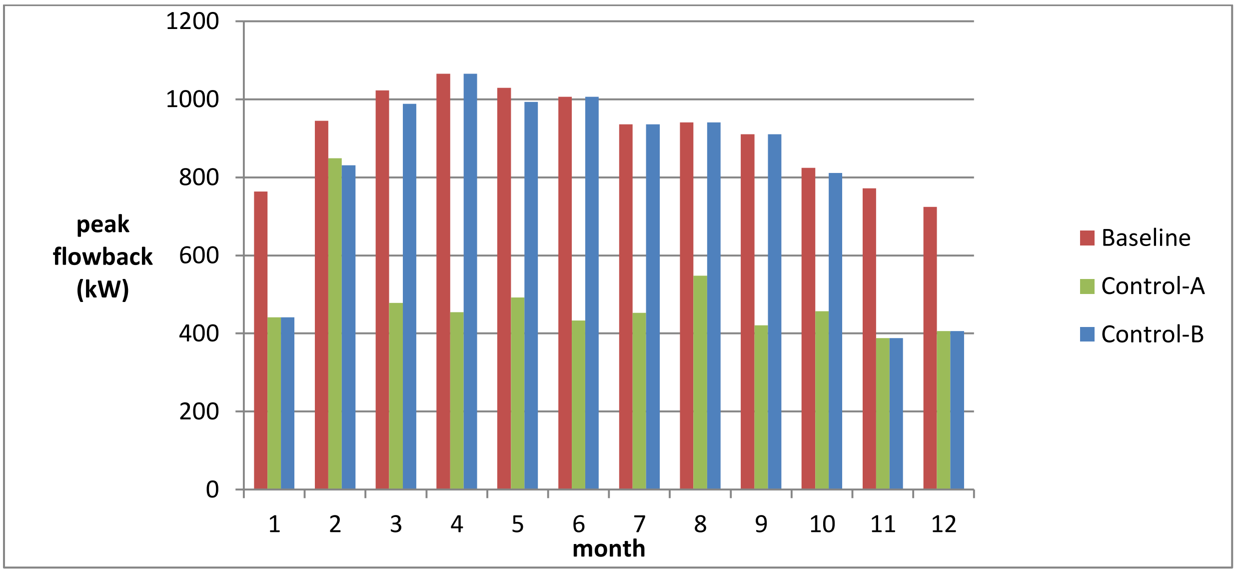

Figure 14: Peak flowback at transformer in case of PV penetration of 50% and no limit on the thermal energy export.

The peak flowback at the transformer is depicted in Figure 14 and Figure 15 for the 50% and 75% PV penetration, respectively. The figures show that even Control A, which always tries to release heat from the storage as soon as possible, is likely to have – at least once each month - the heat storage in a situation where it cannot be further charged at the moment when there is significant solar irradiation. The difference between the PV50% and PV75% scenarios for Control-A in February and March can be best explained by the fact that peak values over such long horizons are heavily influenced by chance.

Control-B – due to its policy to keep the heat storage rather full then empty – hardly improves upon the baseline. Here the probability is apparently high that during an irradiation peak the controller cannot use the heat storage.

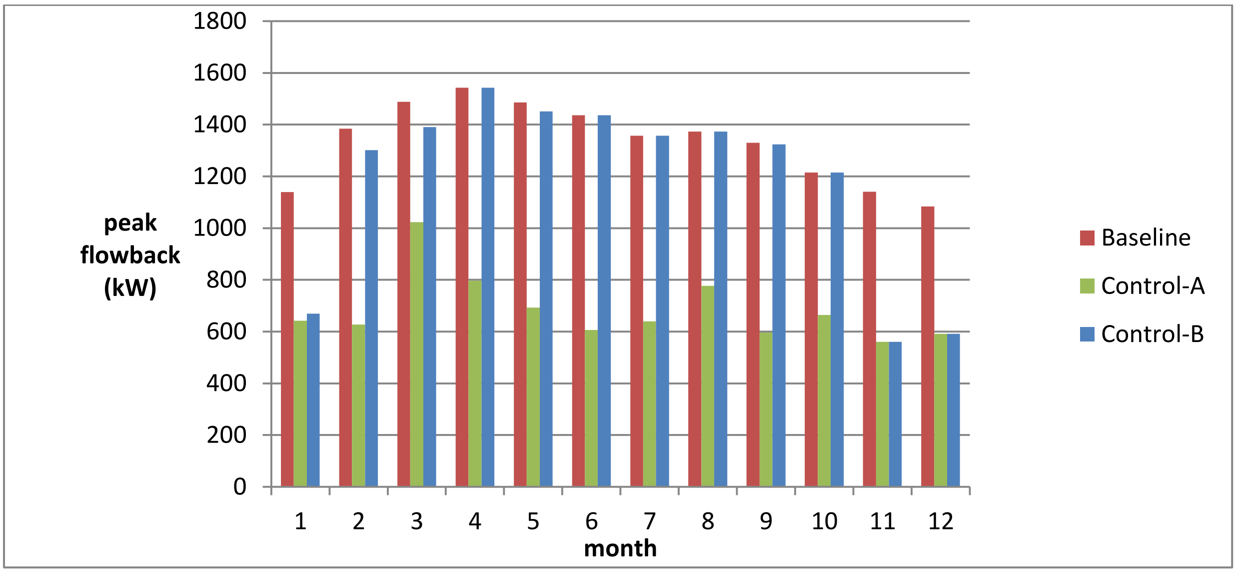

Figure 15: Peak flowback at transformer in case of PV penetration of 50% and no limit on the thermal energy export.

Having observed the remaining flowback of the control strategies for the scenario where the only bottleneck is the heat storage capacity, we now add a second one, looking at the situation of limited heat export to the heating grid of Ulm. The influence of the heat export limit on the total yearly flowback is depicted in Figure 16 and Figure 17. For both control strategies and for both PV penetration levels there is a clear influence. It is more pronounced for Control A, where the flowback increases by a factor of more than five when comparing a 500MW heat export limit with the 100MW limit (red bars in Figure 16). For Control-B the difference is less pronounced; here the ability to consume PV surplus is apparently limited by the heat storage capacity more than by the ability of the Ulm heating grid to consume surplus thermal energy. From a different viewpoint, the advantage of Control A in terms of transformer flowback depends on the ability to export surplus heat. When this ability is limited to say 100MW, as depicted on the left-hand side of the figures, then the performance of Control A and that of Control B are much more similar.

There are no surprises when comparing the 75% PV penetration case (Figure 17) with 50% (Figure 16). The observations made above for the total monthly flowback also apply to the yearly flowback rates, and the influence of the heat export limit for 75% penetration is similar to what we have observed from the 50% figure.

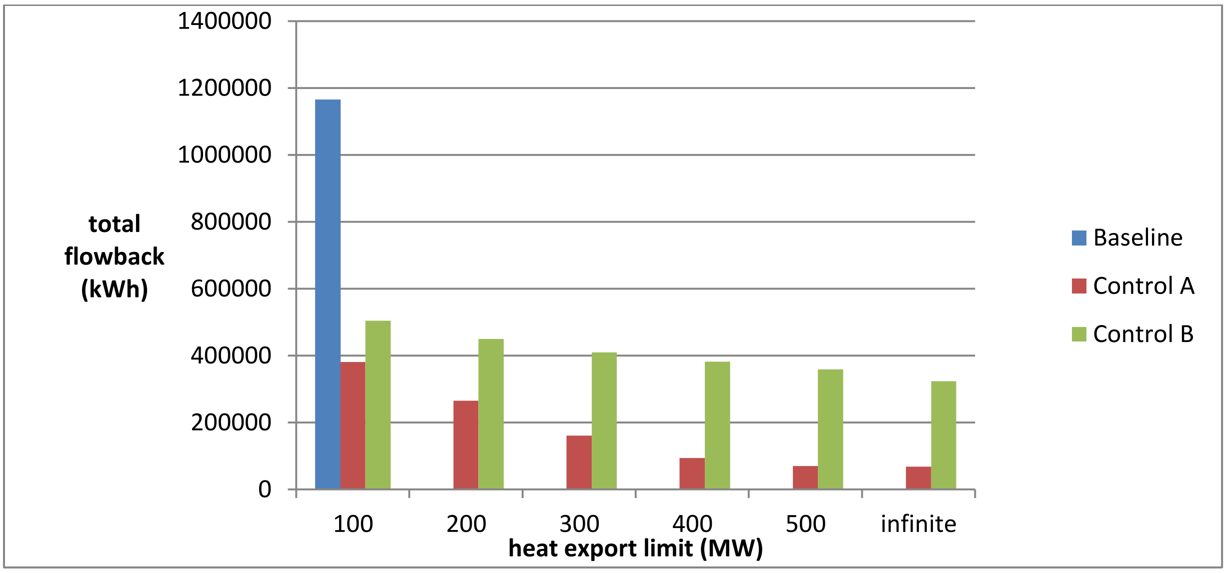

Figure 16: Yearly flowback values for PV penetration 50%.

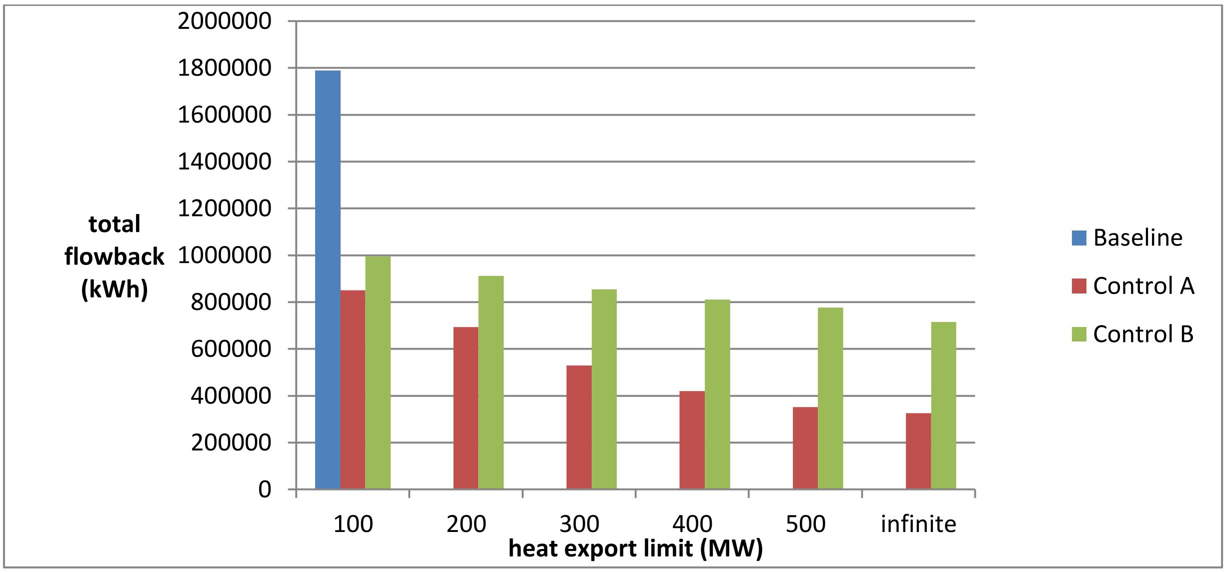

Figure 17: Yearly flowback values for PV penetration 75%.

The flowback into the MV grid at the transformer is a direct indicator of much of the surplus electrical energy is transferred by the coupling points from the electricity network into the heating grid. The influence of the scenario variations and control strategies on other KPIs of the electricity network is shown in Table 2.

The approach of consuming PV surplus at a central large coupling point near the transformer is to quite some degree reducing the amount of overvoltage violation, as shown in the first rows of the table. Control A, which we already know to transfer more surplus energy into the heating network, is, as expected, also more performant in terms of the node voltage KPIs. Especially critical voltage violations – which occur only in case of 75% PV penetration – are reduced by Control A by more than 90%.

		Baseline	Control A		Control B	
			100MW limit	No heat export limit	100MW limit	No heat export limit
node voltage violation incidents	PV 50%	411023	243897	157560	280067	230592
	PV 75%	824998	698899	619921	719333	678284
node voltage violation time (h)	PV 50%	946.5	690.5	582	724.5	667.25
	PV 75%	1386.75	1221.75	1138	1239.5	1198.25
critical node volt. violation incidents	PV 50%	0	0	0	0	0
	PV 75%	34212	19241	2932	22028	14489
critical node volt. violation time (h)	PV 50%	0	0	0	0	0
	PV 75%	261.75	166	48.75	184.25	127.5
line load violation incidents	PV 50%	40497	41455	41925	41273	41541
	PV 75%	88531	89207	89672	89106	89311
line load violation time (h)	PV 50%	896	900	900.5	899.75	899.75
	PV 75%	1356.5	1359.5	1363.75	1358.5	1361.25
critical line load violation incidents	PV 50%	10321	10986	11516	10820	11077
	PV 75%	62987	63754	64211	63563	63843
critical line load violation time (h)	PV 50%	514	527.25	535.75	524.75	529
	PV 75%	1105.25	1113.25	1117.25	1111.75	1115
transformer load violation time (h)	PV 50%	722.75	260.75	0.25	367.25	222
	PV 75%	1211.5	517.75	4.75	651.5	388.5
Critical transf. load violation time (h)	PV 50%	288.5	126.5	0.25	170.5	104.5
	PV 75%	961.5	430.5	0.5	544	326.25
Peak transformer load (%)	PV 50%	128.327	128.003	102.459	128.327	128.327
	PV 75%	185.077	185.077	123.253	184.532	185.077

Table 2: Influence of scenario variations and control strategies on the electricity grid.

For the electric lines adding a large electricity consumer next to the transformer cannot be expected to make a major difference as compared with exporting the PV surplus via the transformer to the MV network. Indeed, the corresponding table rows show that line load violation is not reduced in any of the scenarios; the situation even becomes slightly worse by this additional consumer.

The picture looks more promising when observing the transformer load violation KPIs at the bottom rows of Table 1. We know already from discussions above that our particular hybrid approach does reduce the flowback, and so also transformer overload is significantly reduced. Especially for critical transformer load violation the heat demand limitation has a clear influence, and for all these KPIs Control A shows a better performance. The peak transformer load – similar to the peak flowback as discussed above – is reduced only moderately by the hybrid control strategies.

5.2 Heating Side

The primary benefit of the hybridization expected on the heating side is the reduction of energy that needs to be imported from the wider heating grid of Ulm. Figure 18 visualizes these numbers on a monthly basis for the scenario where there is no limit on the thermal energy export. The figure demonstrates that the relative reduction of thermal energy import is small. Both Control A and Control B reduce the import by less than 20% even in summer.

Another observation is that, in terms of this KPI, Control B has an advantage over Control-A. The policy of Control B to keep the heat storage charged, discharging only what is needed to satisfy local demand and what is needed to avoid overcharging, leads to more local usage of locally produced thermal energy. This is remarkable since the above analysis of the electricity side has shown that Control A is able to convert more surplus into heat. It should be noted however that the satisfaction of local demand has not been a design goal of Control-A – recall that it is designed to always maximize the amount of heat released from the storage, regardless of the current local heat demand.

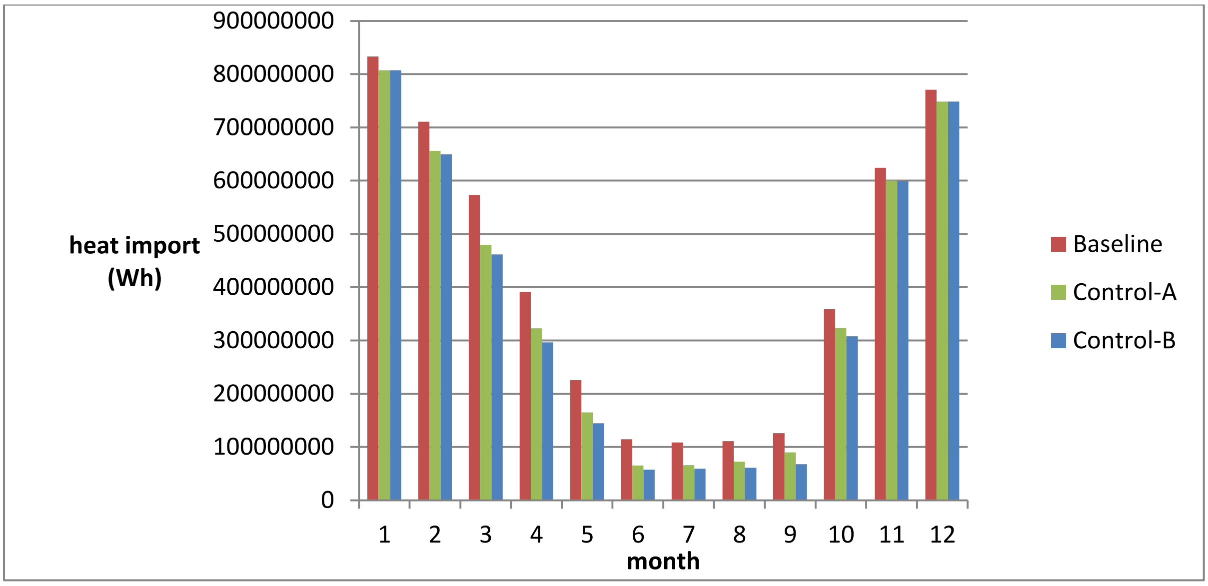

Figure 18: Heat import from the Ulm heating grid for PV penetration 50% and no heat export limit.

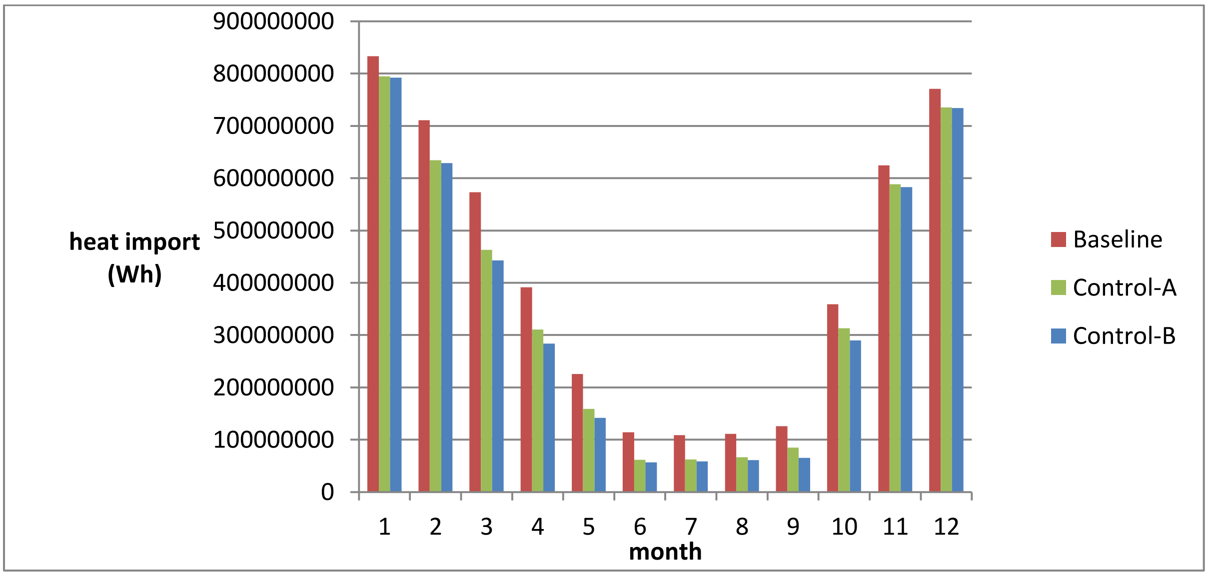

Figure 19: Heat import from the Ulm heating grid for PV penetration 75% and no heat export limit.

Figure 19 visualizes the findings for the PV penetration 75% scenario. Of course the numbers of the baseline are the same here because the effects of a higher PV penetration rate affect only the electricity network as long as there is no coupling point in use. The reason why we include the figure is because it shows that the increased availability of PV surplus leads to a – very small – increase in the amount of thermal energy which is used for local heating.

We next investigate the influence of heat export restrictions on the heat import. What can be expected, at least for Control-A, is that with more restrictions regarding thermal energy export more energy will remain in the storage and thus can be used for local heating. This expectation is confirmed by Figure 20. For an import limit of less than 300MW Control-A even imports less energy than Control-B, which can be explained by the above observation that Control-A is able to turn more PV surplus into heat, and the export limitation forces Control-A to use more of that heat locally.

Also Control-B experiences a slight decrease of heat import when there is a limitation on export. As the strategy is designed to satisfy local demand and export only when necessary to keep the heat storage chargeable, the influence of the export limitation is much smaller. The small influence can be explained by the heat storage being full more often when export is limited, and therefore slightly more of the local heat demand – which has turned out to always exceed the local production – can be satisfied from the storage.

We omit the figure for PV penetration 75%, because it is very similar to the 50% case and all observations hold here as well.

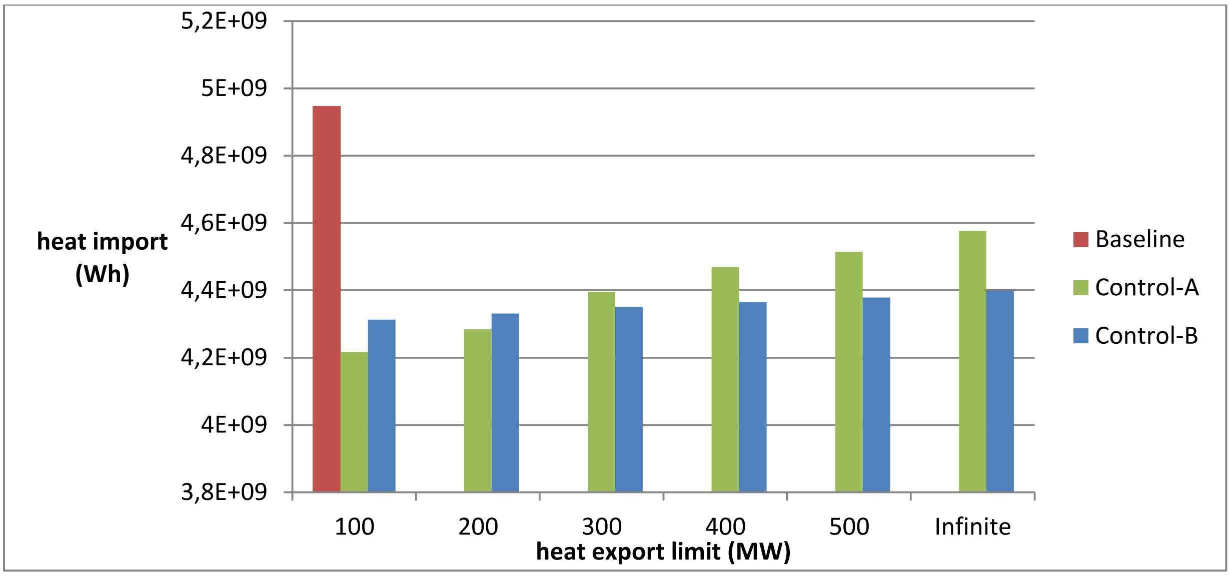

Figure 20: Yearly heat import from the Ulm heating grid for PV penetration 50%.

The heating pipes between Ulm and Einsingen are about 3km long, so heat transfer via them is subject to temperature losses. The yearly energy loss in the heating grid – including both the grid of Einsingen and the connection pipes to Ulm - is visualized in Figure 21. Control A – due to its more aggressive export of thermal energy – experiences more grid losses than Control-B, and this loss increases with the heat export limit.

Also Control-B experiences extra grid losses as compared to the baseline, but they are less than Control-A's losses, and they are less influenced by the heat export limit. But overall only little is changed by the hybridization in terms of grid losses, which is due to the fact that only a small proportion of the local heat demand is satisfied from PV surplus. Figure 22 shows the losses for 75% PV penetration, which are nearly identical.

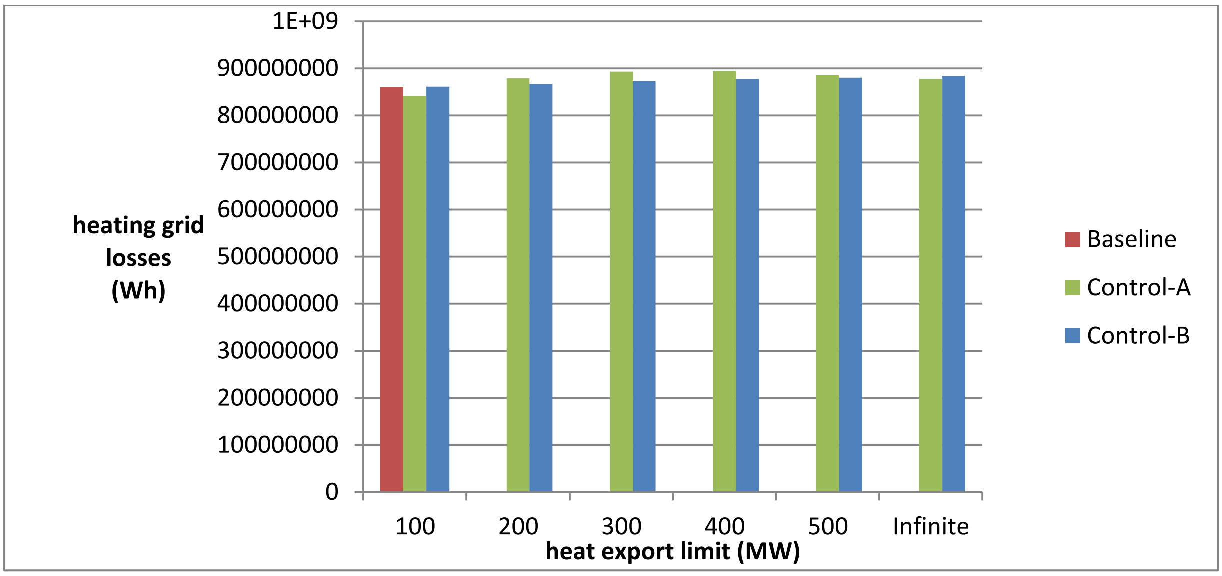

Figure 21: Yearly heating grid losses for PV penetration 50%.

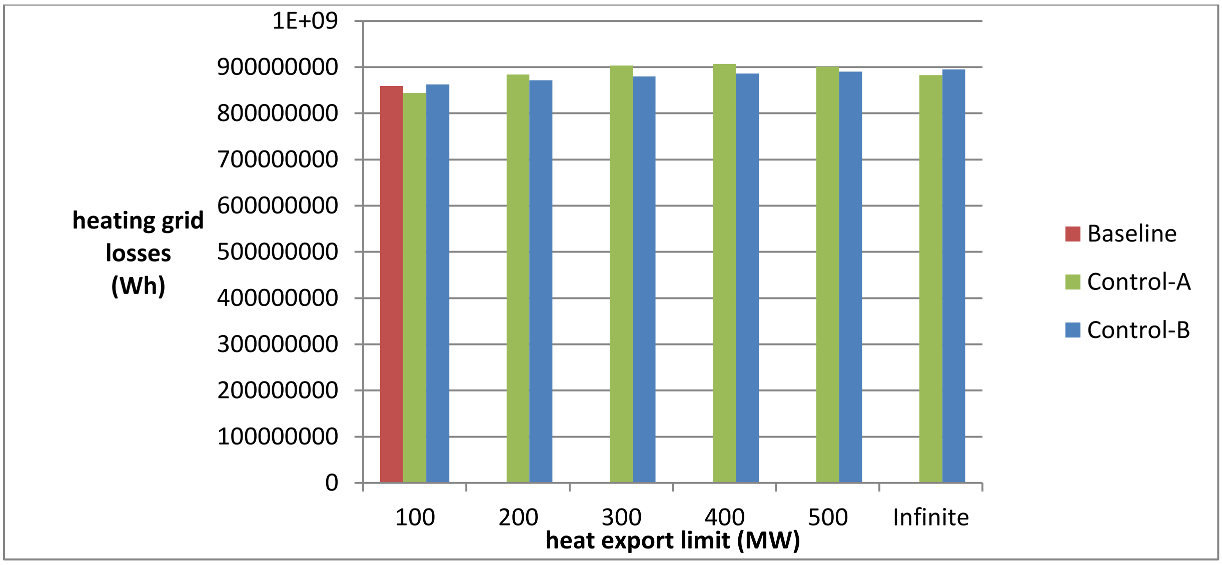

Figure 22: Yearly heating grid losses for PV penetration 75%.

5.3 Results Summary and Conclusions

We have studied a hybridization approach where a central electric boiler and heat storage are used as coupling points transferring energy from the electricity grid to the heating grid. The control strategies for the coupling point where designed such that only local surplus energy from PV panels is used.

Our experiments have demonstrated that some of the problems in the electricity grid that come from excessive local PV usage can be mitigated. Overvoltage, flowback, and transformer overload could be significantly reduced.

The experiments have also shown some of the limitations of large centralized grid coupling points. Despite heat storage discharging policies that should in theory always leave enough room for further e-boiler usage, in practice the storage was too often in a state where it could not be further charged from the e-boiler. As this also happens at times when solar irradiation is at the peak, the peak flowback and peak transformer load values were not significantly reduced by this particular hybridization approach – but of course the total time spent in such critical situations is much less with hybrid control. With a larger number of smaller coupling points of that kind, some of them will remain usable all of the time with high probability, and so the peak flowback/load could be reduced more. Another limitation of the centralized approach is the ability to reduce line overload.

On the heating side we have seen that energy from PV surplus reduces usage of energy from the heating grid of Ulm, and heating energy can also be exported. Local usage has turned out to be preferable, as the export causes more energy loss in the grid. A limitation of the export is increasing local usage and decreases energy losses, but it also reduces the total amount of surplus electricity which can be converted into heat by our control strategies.

From our observations there is a preference for Control-A, because it has shown clear advantages in terms of the electricity network KPIs, while the disadvantages on the heating side in comparison to Control-B much are less pronounced.

6 Skellefteå Future Scenario: Utilizing Industrial Waste Heat Using a Heat Pump and Battery.

In the present-day scenario for the Skellefteå target site a hybridization setup has been studied in D5.3.1 [1] using an electric boiler to transfer energy from the electricity grid to the heating grid, where the objective has been to reduce the dependence on fossil oil and to make heating more economic. The future scenario for the Skellefteå site enhances this scenario by additional consumers, storage, and a new coupling point.

6.1 Scenario Description

We assume that an industrial consumer of electrical energy, for example a datacenter, is moving to Skellefteå. This industry is close to the location of the existing CHP plant, so the electricity produced here can be directly used, either to cover the electricity needs of the industry, or to charge a battery installed at the same site. We furthermore assume that the industry produces a steady heat output equivalent to its electrical load, and this waste heat can be made available for the heating grid of Skellefteå by a heat pump (low temperature level of the waste heat that has to be lifted to the required network supply temperature). Also the heat pump can directly consume electricity from the CHP or from the battery, and thus energy taxes and electricity network and market charges can be avoided as compared to the situation where the CHP would sell electricity and the industry and heat pump would have to buy it again on the market.

We still consider the heat production devices from the previous current-day scenario to be available, that is, there is a 25MW biomass boiler, the CHP, and the electric boiler which has previously played the role of the new coupling point. Unlike in the previous scenario, we here assume that oil heating does not play a role anymore, and instead sufficiently large electric boilers are installed in the city to provide heat when the demand exceeds what the other devices can produce. This differs from a variation of the present-day scenario where the e-boiler had been assumed to be located next to the CHP. In the new scenario, the role of that main coupling point is played by the heat pump, whereas the city-side e-boilers are serving as backup devices.

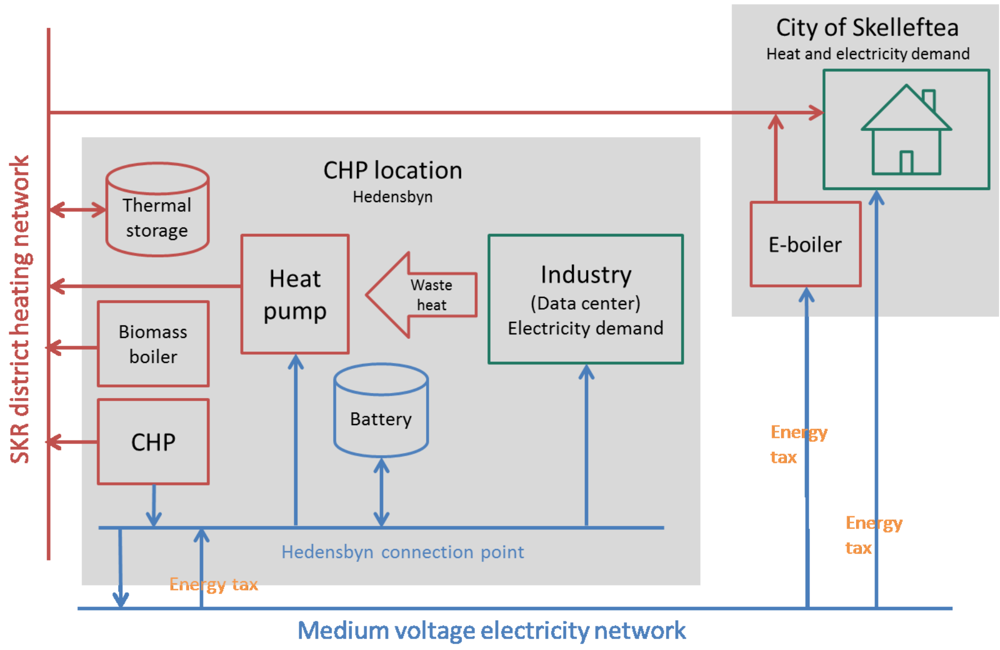

Figure 23: Schematic view of the Skellefteå Future Scenario

The scenario is depicted by Figure 11, where the heating network is symbolized by red lines, the electricity network is associated with the blue lines and energy tax and network charges are applicable on all energy transfers via outgoing links of the medium voltage network.

An overview of the technical specifications of the relevant devices and networks of this scenario is given in the following table.

Participant	**Specifications/Variations**
Skellefteå heat demand	Based on historic data from 2014 (typical winter variation of present-day scenario). Variations assume the demand to increase by up to 20%.
Skellefteå electricity demand	Same as in present-day scenario.
Electric boiler	Installed close to the heat consumers in the city. Heat output is continuously variable; no upper bound of the maximum heat output.
CHP	Always running, heat output continuously variable between 18.0MW and 62.9MW, electricity output is approximately proportional to heat output and has a maximum of 34,6MW. Maximum output change rate is 11.5MW (heat) per hour. Efficiency of conversion from biomass into heat & electricity is 79%. Operational costs of 5.4 EUR/MWh.
Biomass boiler	Maximum output 25MW; minimum output when running is 6.25MW. Maximum output change rate is 10% per 15 minutes. Requires 8h of ramp-up time before it can produce heat. Energy efficiency of 80% in converting biomass into heat. Operational costs of 5.4 EUR/MWh.
Thermal storage	Capacity of 1000MWh; needs to be maintained at charging level of 35%.
Industry (data center)	Electricity consumption of 10MW, 20MW, 30MW, 40MW (scenario variations), production of same amount of waste heat. Waste heat requires heat pump to become usable in heating grid.
Heat pump	Maximum output depending on the required heating pipes supply temperature and the available waste heat. Electricity needed is a factor between 0.4 and 0.29 of the desired output temperature.

Battery	Capacity is a variation parameter, taking values 1MWh, 5MWh, and 10MWh. Can be fully charged/discharged within 1h.
Electricity market	Spot market prices as in present-day scenario (see D5.3.1). Using electricity from the wider grid additionally costs 19.5EUR/MWh energy tax, 3.05 EUR/MWh market fees and 3.38EUR/MWh network charges.
Biomass price	20.77 EUR/MWh

6.2 Control Strategies

Baseline: Present-day Scenario Hybrid Control

The Skellefteå future scenario is an enhancement of the previous present-day scenario, and it is based on the assumption that oil is not used anymore for heating. The electric boiler, which was the new coupling point in the present-day scenario, is now the source of heating when demand peaks cannot be satisfied with the heat storage and the two biomass-based heating plants. Thus, the baseline for the future scenario is acting like a hybrid control strategy for the present-day scenario. As oil is not considered an option anymore, there is no distinction between cost-best control and oil-out control like it was before. We apply a set of rules about when to charge the heat storage and when to switch on the biomass boiler, and this set of rules further determines a prioritization of the different devices to be chosen as heat sources to cover the demand and/or charge the heat storage.

As a summary of these rules, the CHP is always running with maximum output in order to maximize the revenue from electricity sales. The only exception is when its heat output would exceed the demand and the heat storage is already full. The biomass boiler is only switched on when a high heat demand is expected, and then it is used to charge the heat storage together with the CHP. Discharging of the heat storage takes place when the heat demand exceeds the load that can be satisfied by the CHP and the biomass boiler, and the electric boiler is used as a backup if the heat storage is not sufficiently charged or of its maximum heat output does not suffice.

The rules are described more formally as follows.

```
CHP:
- set to full heat (and electricity) output unless the heat storage is
already full
- assigned priority 1 in satisfying heat demand

Biomass Boiler:
- decided at the beginning of each day whether to turn on or off
- turned on if
      - CHP INSUFFICIENT condition holds, or
      - PEAK EXPECTED condition holds
- set to full output if heat storage not full and PEAK EXPECTED condition
holds, or if heat storage is about to run empty.
- assigned priority 3 in satisfying heat demand

Heat Storage:
- always charged when CHP and Biomass Boiler produce more than the demand
- assigned priority 4 when PEAK EXPECTED condition holds, otherwise
assigned priority 2
- adding 10MW to the city’s heat demand for charging when storage
temperature is about to become critically low
```

```
Electric boiler
- assigned priority 5 in satisfying heat demand

CHP INSUFFICIENT condition holds if within the next 24 hours the total heat
demand exceeds the maximum thermal energy that can be produced by the CHP
during one day.

PEAK EXPECTED condition holds if within the next 72 hours there will be a
situation where the maximum instantaneous heat production of the CHP and
the biomass boiler is not sufficient to cover the demand.
```

Cost-best or Control-R: Minimizing the Costs in each Time Step

The hybrid control strategy we are employing uses a linear model to optimize in each time step the cost of satisfying the heat and electricity demand. Decisions that need some consideration of the future because they affect stateful parts of the setup (biomass boiler ramp-up, heat storage charging/discharging, battery charging/discharging) are partly handled by a rule-based approach. This strategy is also called Control-R (reactive control).

As a summary, the linear model takes into account electricity market prices, maintenance costs, taxes and other charges as well as the biomass prices. Each kWh of thermal or electrical energy generated by some device (or imported from the market) incurs a certain cost, and for each time step a combination of device configurations minimizing that cost is computed by a linear solver, where the main constraint is that the heat and electricity demand has to be satisfied. The linear model is presented in more details in the remainder of this subsection.

The ramp-up decision for the biomass boiler as well as the decision about whether to aggressively charge the heat storage are similar to the baseline, here only taking into account the availability of the heat pump by modifications of the conditions using forecasts.

```
PEAK EXPECTED: true if within the next 72h there is a situation where the
instantaneous heat demand exceeds the max CHP + Biomass + Heat Pump
production capacity.

CHP+HP INSUFFICIENT: true if within the next 24h the total heat demand
exceeds the maximum thermal energy that can be produced by the CHP and Heat
Pump during one day.
```

Based on these modified definitions, it is decided whether or not to start the biomass boiler:

```
At the beginning of each day, switch biomass boiler on if CHP+HP
INSUFFICIENT or PEAK EXPECTED holds.
```

The decision on whether to aggressively charge the heat storage is taken by the following criterion:

```
When PEAK EXPECTED and the heat storage is not yet full, set CHP,
heat pump and biomass boiler to the maximum heat output possible at
that moment.
```

Whenever this maximum output exceeds the instantaneous heat demand, the surplus thermal energy will flow into the storage. Note that the maximum output of the biomass boiler might be zero when it is not running, and at any particular moment the maximum output of the CHP and biomass boiler may be less than the theoretical maximum due to the limited dynamicity of output. Also the maximum output capacity of the heat pump is not constant but changes over time.

The optimization model executed in each time step uses an objective function with is a combination of real costs and virtual costs, where the virtual costs are used to decide on charging or discharging the battery. The overall optimization problem to solve in each time step is as follows.

```
minimize real costs  +  virtual costs

subject to

      heat demand constraint
      heat storage charging constraint
      electricity import constraints
      device boundary constraints
```

The *virtual costs* are defined as

```
virtual costs = - average_electricity_buying_price ·battery_in
```

Thus, the amount of electricity with which the battery is charged is treated like the sale of the same amount of electricity, where not only the average market price is earned but also the taxes and market fees. Intuitively, this amount is what can be expected to save in the future by using the battery energy to avoid buying electricity from the market. As an effect,

- it will be preferred to charge the battery instead of selling energy when the current selling price is below the average buying price.
- charging by additionally buying energy will be done when the current electricity buying price (i.e. market price plus taxes and network charges) is below the average.

Conversely, discharging the battery is treated as a virtual cost. Intuitively, this can be seen as paying back the virtual money earned during charging.

- Discharging for the sake of selling more energy will be done when the current selling price is above the average buying price.
- Discharging for the sake of avoiding to buy energy will be done when the current buying price is above the average.

The *heat demand constraint* mandates that the total heat production matches at least the current heat demand:

```
CHP_hout + biomass_out + heatpump_out + eboiler_out ≥ prod_demand,
```

where the *prod_demand* value on the right hand side is defined by

```
   prod_demand = consumer_demand – hstore_maxout.
```

The variables on the right-hand side represent the current demand of the consumers and the current maximum admissible heat output of the heat storage, which depends of course on its charging level and is zero when the heat storage is empty or not usable.

The h*eat storage charging constraint* mandates that the heat storage is charged when a peak is expected. The following constraint is therefore used only when the heat storage temperature is below a critical value, or when the PEAK EXPECTED condition holds and the heat storage is not already full.

$$\text{CHP\_hout} + \text{biomass\_out} + \text{heatpump\_out}$$

$$\geq$$

$$\text{CHP\_max} + \text{biomass\_max} + \text{heatpump\_max}$$

In other words, the output values of these three devices are forced to their maximum whenever the constraint is active. Note that the values on the right-hand side are changing over time, depending on the previous output of the CHP, the on/off state of the biomass boiler, and the current maximum output of the heat pump.

The *electricity import constraint* is an auxiliary constraint which enables the linear model to treat sales of electrical energy (which generate income determined by the current energy market price) differently from electricity imports (which cause costs determined by the current market price, market fees, taxes, and network charges). We require a variable *electricity_import* defined as

$$\text{electricity\_import} = \max(\text{eboiler\_out}, \text{e\_consumption}),$$

with *e_consumption* defined as the sum of the electricity consumption/production of all participants (CHP, battery, industry, heat pump, e-boiler), where the producers (CHP, battery when discharging) contribute to the sum with a negative sign. The reason for the *electricity_import* variable to be lower bounded by the e-boiler output is the location of the electric boiler at the city site, which effectuates that energy taxes and market fees always have to be paid when using it.

The above nonlinear definition of *electricity_import* is linearized by a pair of constraints.

$$\text{electricity\_import} \geq \text{e\_consumption}$$

$$\text{electricity\_import} \geq \text{eboiler\_out}$$

In the objective function, the electricity import is represented as part of the *real costs*:

$$\begin{aligned}&\text{real\_costs}\\&= \text{e\_consumption} \cdot \text{electr\_price}\\&+ \text{electricity\_import}\ (\text{e\_tax} + \text{network\_charges} + \text{market\_fees})\\&+ \mathit{other\_costs},\end{aligned}$$

where *other_costs* represents the price for biomass and the maintenance costs.

6.3 Scenario Variations

For each scenario variation, as in the Skellefteå present-day scenario, the winter months from November to March are simulated. Each variation is characterized by the following parameters.

- Electricity tax, taking the two value of 19.5 EUR/MWh and 0.51 EUR/MWh. The former represents the current tax in Sweden, while the latter is a new reduced tax planned to be applied to datacenters in Sweden.
- Heat demand, taking values of 0%, 5%, 10%, and 20% of the typical winter situation in the previous Skellefteå present-day scenario.
- Industry electricity load, taking values of 10MW, 20MW, 30MW, and 40MW.
- Battery capacity, taking values of 1MWh, 5MWh, and 10MWh.
- Control Strategy: Baseline or Cost-best (Control-R).

7 Skellefteå Future Scenario: Results

7.1 Energy Cost

As our hybrid grid control strategy is aimed to minimize the costs in each time step, we first have a look at this KPI. Figure 24 compares the baseline, which uses only the CHP and the e-boiler as coupling points, with Control-R which additionally controls the heat pump and the battery. Apparently the additional means of hybridization results in a savings of about 20%. This is observed for various configurations of the city's heat demand, whereas of course the cost of both control strategies increase with the heat demand.

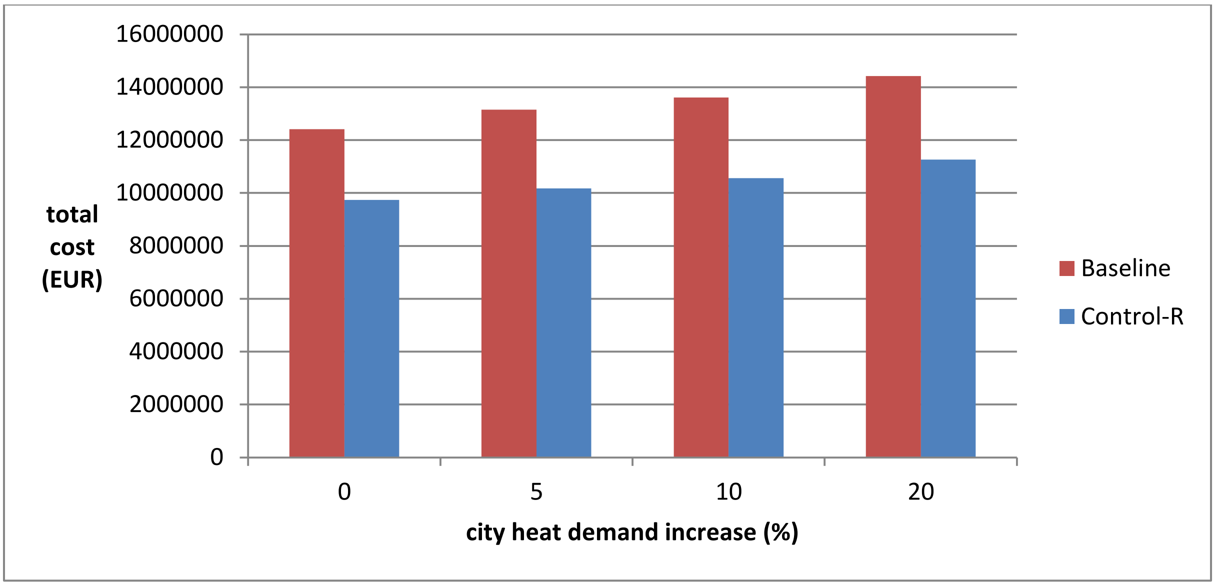

Figure 24: Total cost for covering the heating demand and the industry's electricity demand, assuming a battery size of 1MW, an electricity load of the industry of 20MW, and an energy tax of 19.5 EUR/MWh.

While Figure 24 visualizes the results for an assumed energy tax of 19.5 EUR/MWh, we compare this with the situation of a reduced energy tax of 0.51 EUR/MWh in Figure 25. Here not the absolute costs are shown, but the cost savings achieved by Control-R using the heat pump and the battery. As the relative savings are slightly higher in the case of a higher energy tax, which is an indicator that a major proportion of the savings come from reducing the electricity consumption. This is what can be expected, because the heat pump available to Control-R requires less electricity to produce the same amount of heat.

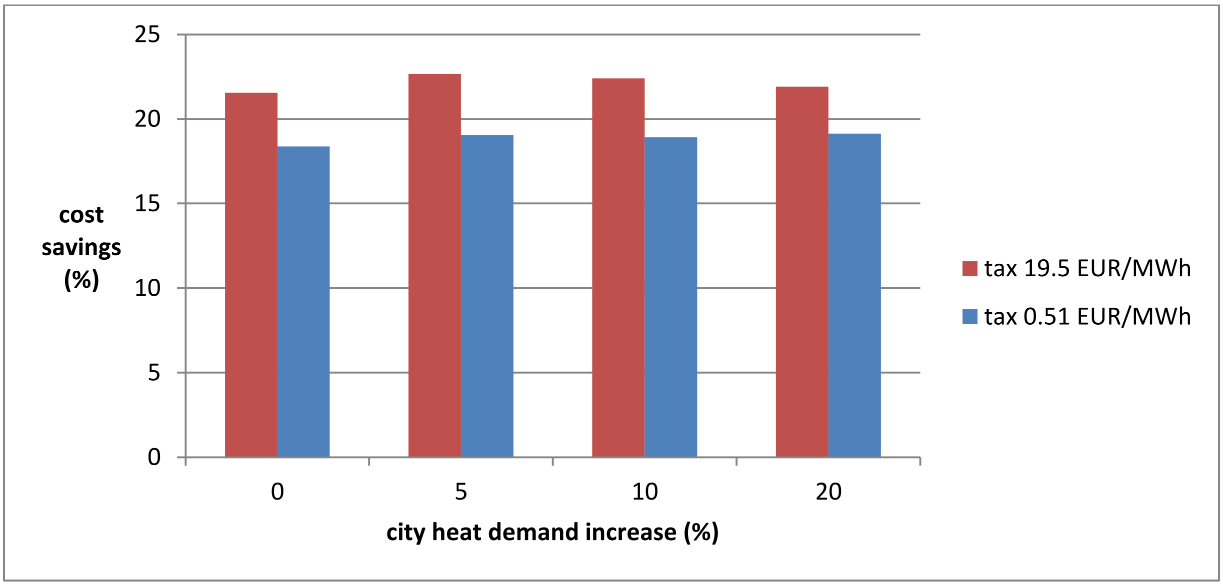

Figure 25: Cost saving of Control-R as compared to the baseline, assuming a battery size of 1MW and an electricity load of the industry of 20MW.

To study the effect of the electrical storage battery, we plot the costs against the battery size in Figure 26, assuming here no city heat demand increase. The figure demonstrates that the influence of the battery is so small that it is not even visible; in numbers it improves less than 0.1% of the costs. A much larger battery might have the potential to improve more, but results of WP3 have shown that large batteries are not an option from the economic point of view due to the installation and maintenance costs. As also for further KPIs the battery size does not exhibit any positive or negative effect, we assume its size to be fixed to 1MWh in the remainder of this section.

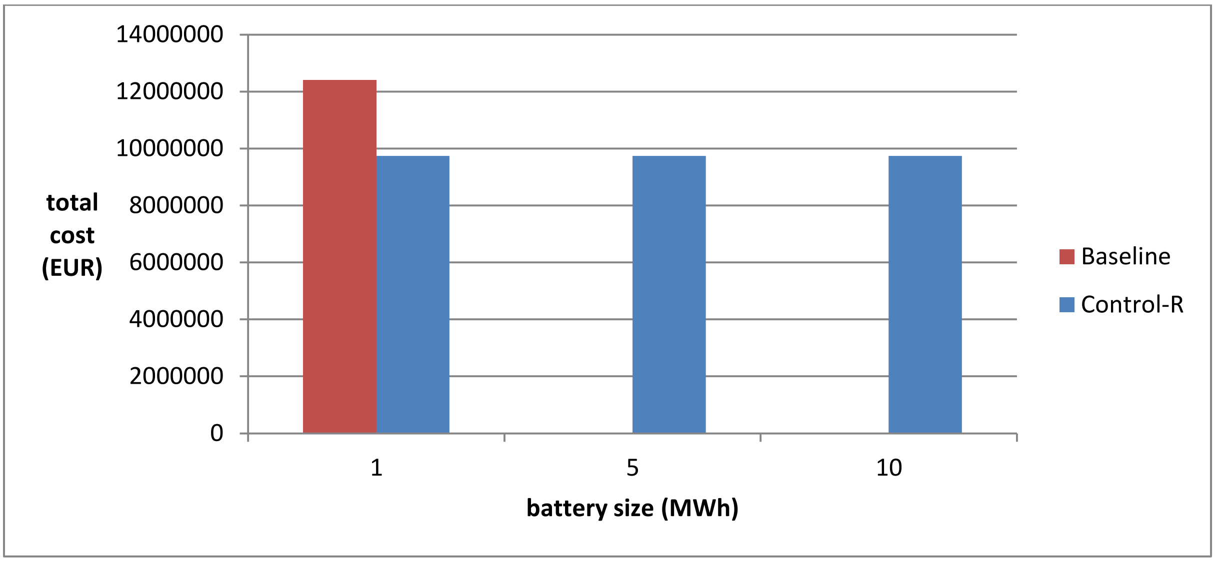

Figure 26: Total cost for covering the heating demand and the industry's electricity demand, assuming a heat demand increase of 0%, an electricity load of the industry of 20MW, and an energy tax of 19.5 EUR/MWh.

We finally have a look at the influence of the electrical load of the industry consumer on the costs. Recall that a higher electrical load also means that there is more waste heat that can be pumped into the heating grid.

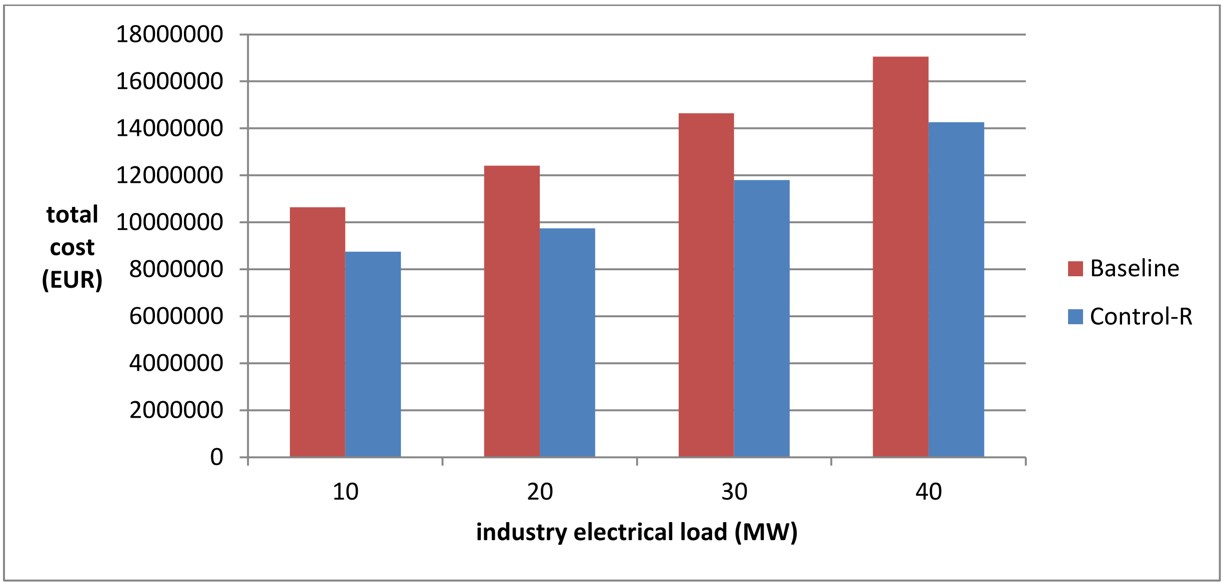

Figure 27: Total cost for covering the heating demand and the industry's electricity demand, assuming a battery size of 1MWh, a heat demand increase of 0%, and an energy tax of 19.5 EUR/MWh.

Figure 27 depicts the costs for various electrical load values, showing a roughly linear cost increase with the industry load for both strategies. Figure 28 gives insights on the cost savings for the two different values of energy tax. The largest *relative* cost savings are achieved with medium industry loads of 20MW or 30MW. This can be explained by the fact that low industry load generates only little waste heath for the heat pump use, whereas high industry load generates more waste heat than can what is needed for the heating grid. In the case of a 40MW load, the relative savings are even higher when the tax is lower. This is because here the higher tax applies mostly to the large amount of the energy that has to be imported for the industry by both control strategies, and much of the resulting waste heat remains unused by control-R.

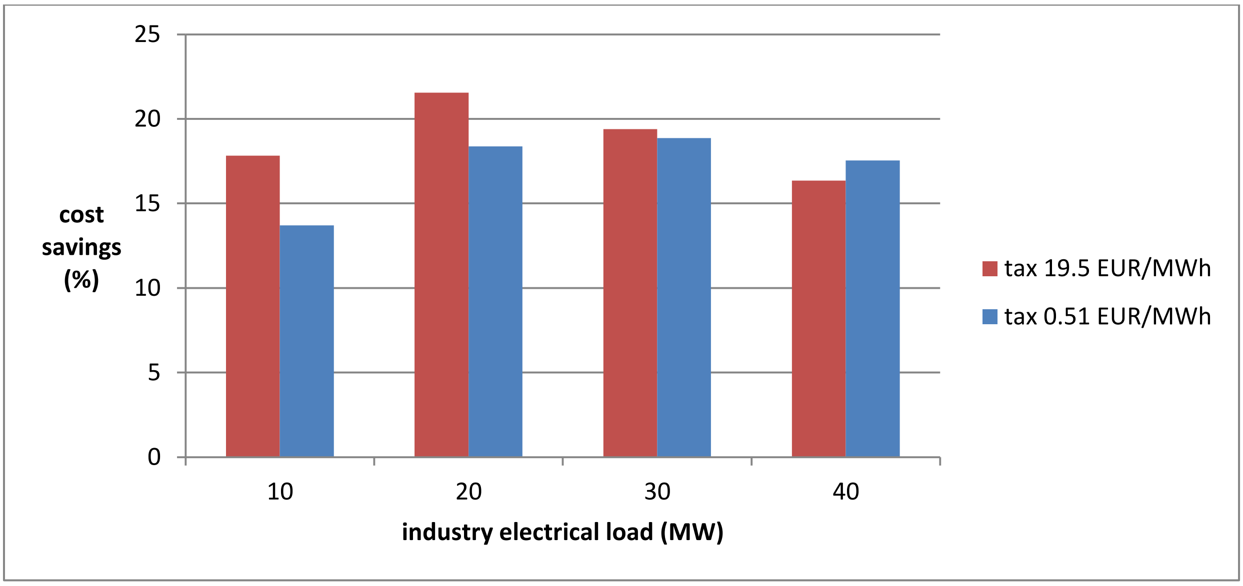

Figure 28: Cost saving of Control-R as compared to the baseline, assuming a battery size of 1MW a heat demand increase of 0%.

7.2 Electric Boiler Size

In the Skellefteå future scenario we assume that oil is not anymore used for heating, while at the same time the heat demand increases by up to 20%. Thus, both the baseline and Control-R need to use electric heating when peaks occur. In our simulations we have not assumed a fixed size of the electric boiler, but instead we evaluate how large this boiler needs to be in order to provide enough heat in all situations.

Figure 29 shows the required E-boiler size for different heat demand scenarios. The baseline's required e-boiler is around 40MW for heat demand increases up to 10% and more than 70MW in case of 20% heat demand increase. This is considerably mitigated by the heat pump usage of Control-R, where the e-boiler usage peak remains less than 50MW.

The influence of the electric load of the industry is visualized in Figure 30. Clearly, more electric load of the industry leads to more waste heat usable by the heat pump, and this decreases the required size of the electric boiler to 25MW in the best case.

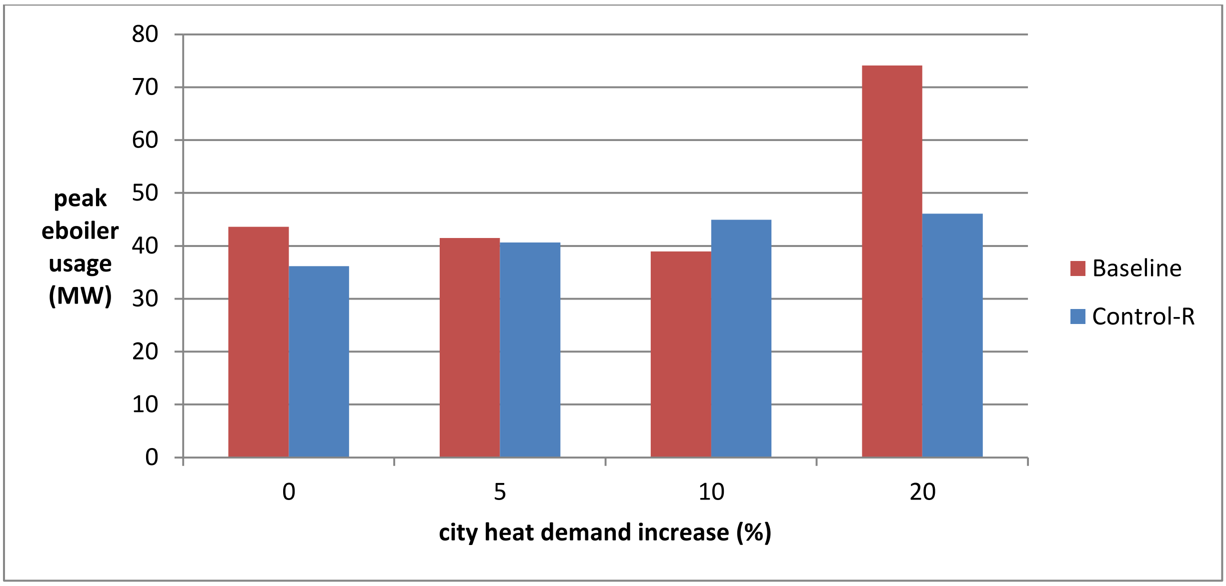

Figure 29: Required E-boiler size, assuming a battery size of 1MW, an electricity load of the industry of 20MW, and an energy tax of 19.5 EUR/MWh.

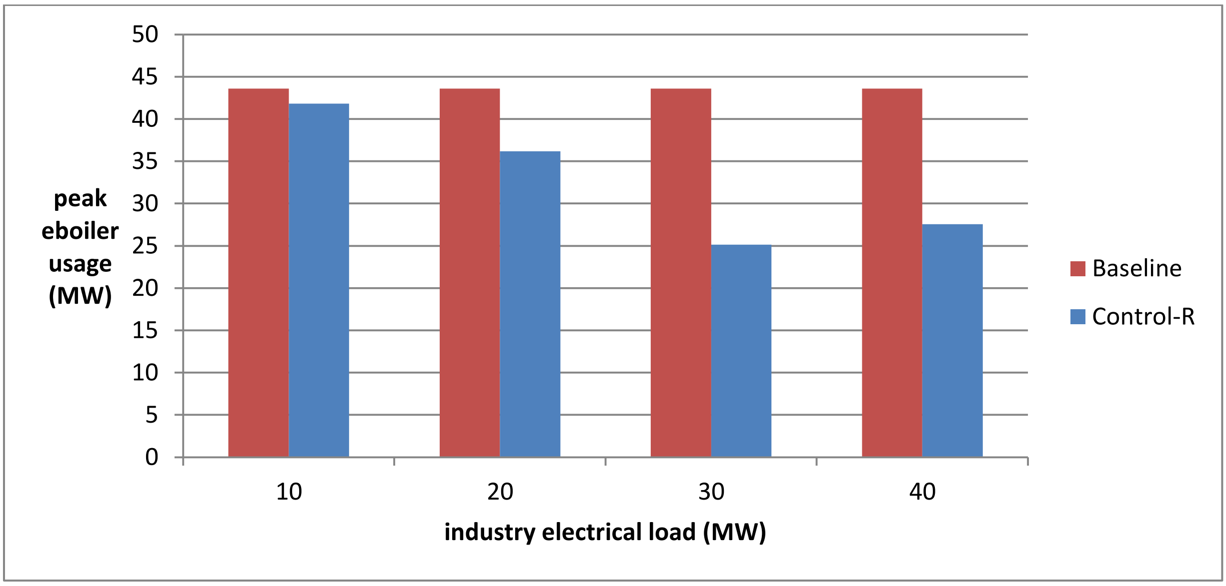

Figure 30: Required E-boiler size, assuming a battery size of 1MW, a heat demand increase of 0%, and an energy tax of 19.5 EUR/MWh.

7.3 Biomass Usage

As the final KPI we look at the amount of biomass that is converted to thermal energy by the control strategies. It is interesting to see how much biomass is replaced by electric heating with and without the availability of the waste energy and the heat pump.

As shown by Figure 30, the biomass usage is decreasing by 10-15% when employing Control-R instead of the baseline, and this happens regardless of the heat demand increase. Note that the plots visualize the total energy produced by biomass usage both by the CHP and the biomass boiler. The influence of the electrical load of the industry is demonstrated by Figure 32. The more waste heat there is available, the more cheap heat can be fed into the network by the heat pump and the less biomass is used. For a 40MW electric load the biomass usage in this scenario decreases by approximately 25%.

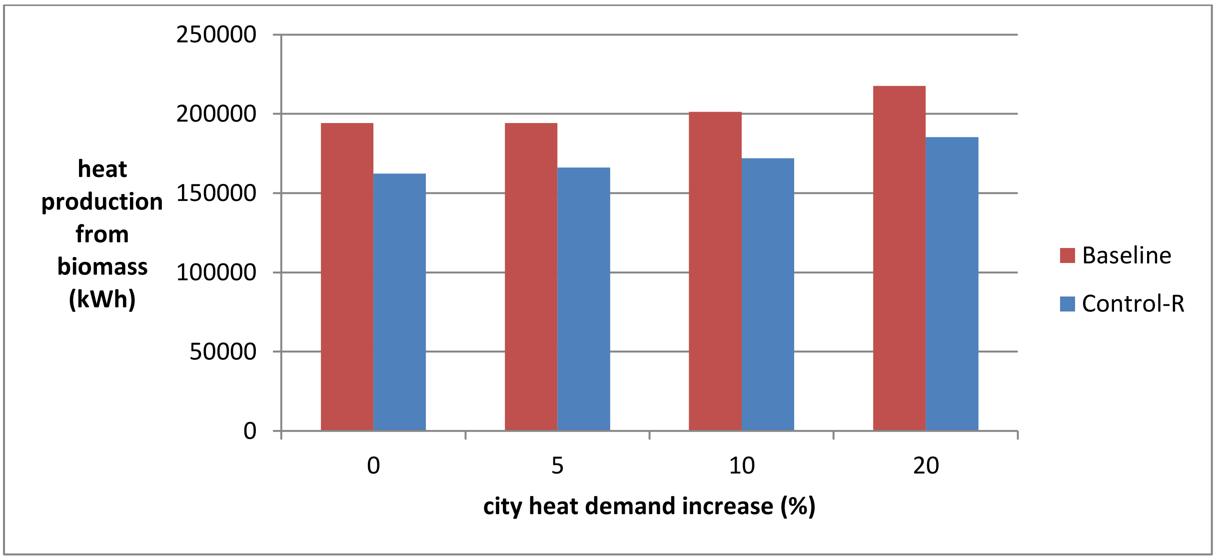

Figure 31: Biomass usage, assuming a battery size of 1MW, an electricity load of the industry of 20MW, and an energy tax of 19.5 EUR/MWh.

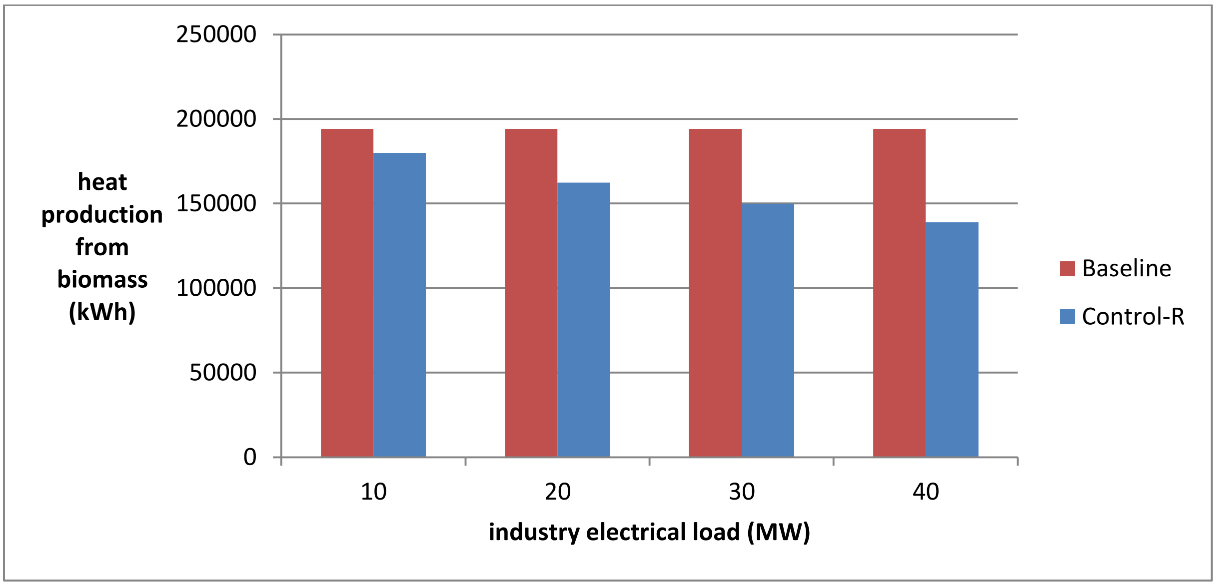

Figure 32: Biomass usage, assuming a battery size of 1MW, a heat demand increase of 0%, and an energy tax of 19.5 EUR/MWh.

7.4 Results Summary and Conclusions

In this chapter we have presented the experimental results for a scenario, where the waste heat of an industrial electricity consumer is fed into the local heating grid by means of a heat pump. Our experiments have shown that this approach does not only decrease operative and energy costs, but also reduces the dependency on less efficient means of heating like the electric boiler. The positive effects were more pronounced when the electric load of the industry was higher; although in terms of relative cost savings a medium size industrial consumer exhibited the best results.

Our experiments have also shown that electrical storage with moderate capacities (1-10MW) does not noticeably influence the costs and other KPIs. Together with the economic analyses of WP3, one can conclude that the battery technology needs to evolve further before it should be considered to be used in hybridization scenarios like the one studied in this chapter.

8 Summary and Conclusion

In this deliverable we have presented and analyzed potential future hybridization scenarios for the test sites of Ulm and Skellefteå. These scenarios comprised new coupling devices such as electrical storage and thermodynamic aspects such as space heating and waste heat from industrial estates. Overall we have demonstrated that the hybridization approach can provide enhancements in KPIs such as cost, electrical grid impact, fossil fuel usage, and CO2 reduction. We have experimented with various hybridization setups and control strategies varying in terms of data usage, conservativeness, and centralization.

While not having systematically investigated the particular aspect of (de)centralization, we can start to draw the conclusion from our experiments that centralized control strategies are preferable to decentralized ones in terms of almost all KPIs, which can be explained by a more holistic overview of the hybrid grids' states. Decentralized strategies – which are still attractive because of their scalability and simplicity - require a very careful control design in order not to have a suboptimal behavior as seen in this and previous deliverable D5.3.1.

We also confirmed the hypothesis that seasonal variations are heavily influencing the outcome of the results, and in particular whether the upfront investments in coupling devices are justifiable with regards to the achieved cost savings. For example space heating in Ulm is only an exploitable coupling point in spring where there are still heating needs and PV surplus starts to be significant as opposed to winter.

Another example of such tradeoffs between upfront investment and return is seen in Skellefteå, where we found that the electrical storage does not in itself have the potential to save much cost, unless electricity market prices fluctuate much more in the future than presently or the investment costs significantly decrease in the future.

This deliverable has presented investigations to demonstrate the usefulness of hybridization, and deliverable D5.5 will provide a more general view on the applicability of these types of control strategies to sites other than Ulm and Skellefteå.

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Disclaimer

The OrPHEuS project is co-funded by the European Commission under the 7th Framework Programme “Smart Cities” 2013.

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