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OPtimising Hybrid Energy grids

for smart citieS

WP2 Technical, Economical and Social Benefits

Deliverable 2.5

Report on the validation of technical, economical and social benefits in the different demonstration sites, with special consideration of robustness tests of business model design

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Deliverable Description

Abstract: Deliverable D2.5 provides the evaluation of the technical, economic and social benefits in the demonstration sites. The today's and future use cases analyzed in the OrPHEuS demonstration sites are described in detail and the corresponding results for tailor-made novel hybrid business models are validated comprehensively. Furthermore, robustness tests are conducted in all of the OrPHEuS use cases, major barriers for new hybrid business models are identified and conclusions and recommendations are provided for WP7.

Key Words: ICT, smart cities, hybrid energy grid, energy saving, demonstrations, smart grid, energy control, monitoring

Document History

Version	Date	Authors	Description
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0.2	2016-08-16	TUW	D2.5 Draft with today's use cases
0.3	2016-11-01	TUW	D2.5 Draft including future use cases
1.0	2016-12-19	TUW	Final Version

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 OrPHEuS project elaborates a Hybrid Energy Network Control System for Smart Cities implementing novel cooperative local grid and inter-grid control strategies for the optimal interactions between multiple energy grids by enabling simultaneous optimization for individual response requirements, energy efficiencies and energy savings as well as coupled operational, economic and social impacts. Starting from existing system setups in two cities, enhanced operational scenarios are demonstrated for today's market setup, as well as for future market visions.

The main scope of the Deliverable D2.5 (Task 2.5) is the evaluation of technical, economical and social benefits in the different demonstration sites. Based on the OrPHEuS use case definition, several specific hybrid scenarios for today's and future markets are designed in cooperation with other work packages. Deliverable D2.5 provides the definition of these scenarios investigated in the OrPHEuS demonstration sites Skellefteå, Sweden, and Ulm, Germany. Furthermore, the respective business models are described in detail, possible regulatory issues are highlighted and the methodology for economic modelling is outlined.

Finally, for each investigated hybrid scenario the relevant KPIs are evaluated in quantitative terms. Based on sensitivity analyses of major model parameters robustness tests are conducted in order to validate technical, economical and social benefits in the demonstration sites in different price, demand and regulatory configurations. Subsequently, for each scenario the most important findings are identified, the implications for different market participants are explained and major conclusions are presented.

Administrative Overview

Task Description

Task 2.5 evaluates the different case studies in the OrPHEuS demonstration sites based on the demo site specific set-up in Task 2.4. By bringing together the results from WP4, WP5 and WP6 and with the evaluation of the economic models developed in WP2 the corresponding technical, economic and social benefits are validated in quantitative terms. Furthermore, robustness tests are conducted on the use cases and business models by varying the key economic parameters and conclusions and recommendations are provided for WP7

Relation to the Scientific and Technological Objectives

Task 2.5 and Deliverable D2.5 are related to the achievement of the OrPHEuS Scientific and Technological Objective STO1: "Creation of the concept for new business models". Here, both business models in today's' and in future markets in the OrPHEuS demonstration are described and validated. Thus Task 2.5 is related to MS2: "Enhanced realizations in today's markets" and MS3: "Concept realizations in future markets".

Furthermore, this document provides the achievement of the following performance indicator:

No.	Objective/expected result	Indicator name	STO	Deliverable	MS	Expected Progress		
						Year 1	Year 2	Year 3
19	Validation of technical, economic and social benefits in the different demo sites	Validation	STO1	D2.5	MS3			1 Due: M3(Draft M27

Relations to activities in the Project

Inputs:

- Task 2.4
- WP4
- WP5
- WP6

Outputs:

- WP7

Terminologies

Abbreviations

MS	Milestone
STO	Scientific & Technological Objective
WP	Work Package
CHP	Combined Heat and Power plant
DSO	Distribution System Operator
O&M	Operation and maintenance
PV	Photovoltaics

Table of Contents

1 Introduction

The main scope of this deliverable is to provide a report on the use cases investigated in the two OrPHEuS demonstration sites, Ulm and Skellefteå, and the respective results. Each scenario that has been investigated from a detailed technical perspective in WP4 and WP5 and from an economic and social perspective in WP2 is described in detail.

Comprehensive technical analyses of the investigated OrPHEuS use cases are provided in the Deliverables D4.3.1 [1], D4.3.2 [2], D5.3.1 [3] and D5.3.2 [4], respectively. This report provides the motivation for different OrPHEuS use case analyses, detailed explanations of tailor-made business models for these case studies in the demonstration sites and the description of the regulatory framework and potential barriers in the examined scenarios. Furthermore, the results of the economic investigations are presented and explained in detail and key performance indicators like fuel usage, greenhouse gas emissions, cost reduction or the Pareto criterion are evaluated comprehensively.

The mathematical methods used for the economic investigations are only indicated for different case studies. For a detailed description of the methodological framework developed for the business model analysis see deliverable D2.2 [5].

Each business model in the investigated use cases has been tested for robustness from both, a technical and an economic perspective, by considering and simulating multiple price, demand, regulatory and other configurations. Qualitative conclusions are then drawn from the quantitative results.

This deliverable is structured according to the OrPHEuS Cooperative Coexistence scientific concept. Firstly, chapters 2 and 3 are presenting the results of the today's scenarios in the OrPHEuS demonstration sites Skellefteå and Ulm, respectively. These scenarios only assume slight modifications of the status quo of energy provision in the demonstration sites. The more advanced future scenarios, assuming significant changes in the technology portfolio of the demonstration sites or in the regulatory framework and trying to fully exploit the coupling of different energy networks, are described and evaluated in chapters 4 and 5 for Skellefteå and Ulm, respectively. Finally, major conclusions from the investigations in the OrPHEuS demonstration sites are presented in chapter 6.

2 Today's scenario in Skellefteå

The first scenario investigated in the demonstration site in Skellefteå focuses on the heat production of project partner, local utility and district heating system operator Skellefteå Kraft (SKR). Motivated by use case 1 "Phase-out of oil usage for peak heat generation" (see Deliverable D2.3 "Report on the definition of use cases selected in the demonstration sites" [6]) it is investigated to which extent and at what cost the installation of an electric boiler as an additional coupling point to the electricity grid could help to phase out oil usage.

2.1 Scenario and business model description

SKR is producing about 400 GWh of heat per year to serve the demand of the customers connected to the district heating network. The base load is provided by the biomass-fired Hedensbyn combined heat and power plant (CHP). The electricity produced by the CHP is sold at the NordPool spot market which generates additional revenues for Skellefteå Kraft. Sometimes it can be beneficial to produce more heat than required to satisfy demand in order to sell as much electricity as possible. For this purpose there is a 15000m³ accumulator tank for hot water located at the Hedensbyn site which can absorb excess heat produced by the CHP and provide it to the district heating network when demand is higher. During colder months the CHP is supported by a biomass-fired boiler, which is also installed at the Hedensbyn site. However, during a few hours of high demand the capacity of the CHP, the biomass boiler and the thermal storage is not enough and oil boilers, which are distributed in the district heating network, have to be operated in addition. This can be observed in Figure 1 showing the load duration curve of Skellefteå Kraft's heat production. The annual share of heat produced from oil boilers amounts to less than 1% of total heat production. However, these boilers are crucial for system stability and security of supply.

Table 1: Installed capacity for heat production in Skellefteå by technology.

Technology	Nominal capacity
Hedensbyn biomass CHP	63 $MW_{thermal}$, 35 $MW_{electric}$
Hedensbyn biomass boiler	25 MW
Hedensbyn thermal storage	Maximal 60 MW (depending on temperature difference to the district heating grid)
Oil boilers	7×12 MW

Furthermore, SKR is expecting a population growth in the city of Skellefteå which is expected to result in an increase of heat demand as well. Figure 2 shows the load duration curve of the heat production of SKR in case of an increase of demand by 30%. In this scenario the oil share in heat production would amount to 4.6%.

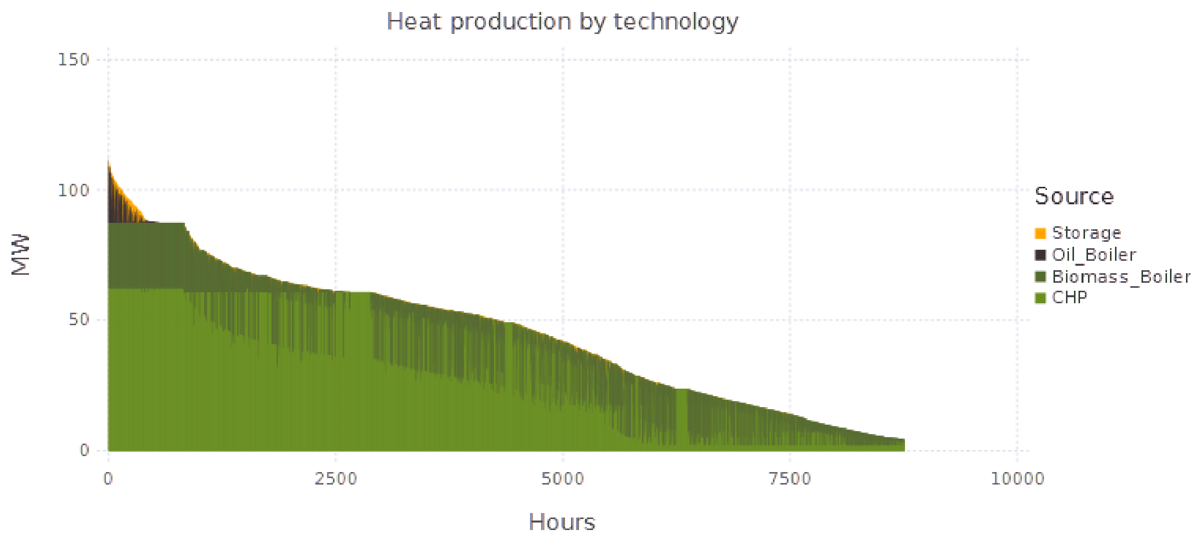

Figure 1: Load duration curve of Skellefteå Kraft's heat production (hours sorted from highest to lowest total production): results from economic model baseline scenario.

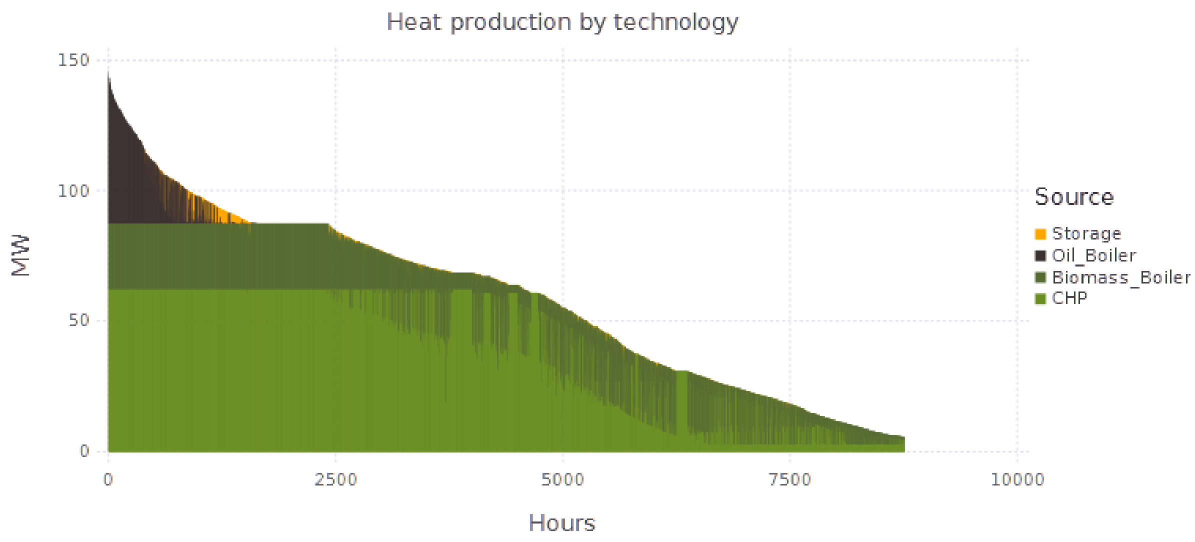

Figure 2: Load duration curve of Skellefteå Kraft's heat production (hours sorted from highest to lowest total production): results from economic model 30% demand increase scenario.

Based on this situation it is investigated, if the installation of a new electric boiler can help SKR to reduce or completely phase out oil usage for heat production. In detail, Skellefteå Kraft could have several business models (or objectives/motivations) in mind for the installation of electric boilers:

1. Install electric boilers to ***reduce oil usage***: SKR is investing in an electric boiler that is used as a one-to-one replacement for the oil boilers and operated whenever the production from the remaining plants is not sufficient. This means that heat production could get significantly more expensive in disadvantageous oil and electricity price constellations.

2. Install electric boilers to ***reduce cost for heat production***: Considering the hourly fluctuation of the electricity spot market prices and the fast-start capabilities of electric boilers motivates the business model of using the new coupling point to react on market signals and thus reducing operational cost for heat production. More precisely, during hours of high heat demand and low electricity prices the electric boiler can be operated instead of oil boilers and if electricity prices are high oil is used. The thermal storage adds even more flexibility to this concept.
3. Install electric boilers to ***prepare for demand increase***: Figure shows that demand increase would also cause a significant increase in oil usage with the current technology portfolio. With the current price conditions this would imply more expensive operation of the district heating system as well, because heat produced biomass is considerably cheaper than heat produced from oil. In order to prepare for higher demand SKR could invest in an electric boiler for mid- to peak-load operation. Note that this business model can generally comprise concepts and objectives of the two previously defined business models.
4. Install electric boilers to ***increase flexibility of CHP operation***: If the electric boiler is installed at the Hedensbyn site, where the CHP and the hot water tank are located, it can be operated with electricity produced by the CHP when NordPool prices are low. Since this happens behind the system boundaries of the electricity distribution system operator (DSO) no network charges and no energy tax on the usage of electricity would have to be paid. This combination of CHP, electric boiler and thermal storage could react very flexible on the heat demand and electricity price signals.

A conceptual overview of the scenario set-up for the heat provision of Skellefteå Kraft with the installation of a new electric boiler is illustrated in Figure 3: Conceptual overview of scenario set-up for the heat provision of Skellefteå Kraft. SKR can use oil boilers, the biomass boiler the CHP, the thermal storage and the electric boiler to satisfy the heat demand of their customers. If the CHP is running electricity is produced as well, which can be sold at the NordPool spot market or used to operate the electric boiler.

Motivated by the business models listed above, several different scenarios regarding the electric boiler size, location and control strategy have been investigated:

- Two different values for the ***nominal capacity*** of the newly installed electric boiler are examined: ***24 MW*** and ***35 MW***. The smaller size will probably be more preferable for the business models aiming to minimize operational costs, while the bigger boiler offers more capacity in the business models regarding an oil phase-out and a future demand increase.

- The second variation concerns the ***location*** of the electric boiler. The investigated candidates are the Dalen site, which is close to the ***City*** and load center, and the Hedensbyn site, where the ***CHP***, the thermal storage and the biomass boiler are located. The major difference between these scenarios can be seen in Figure 3: The interactions indicated by the striped arrows are only possible if the boiler is installed at the CHP location. Otherwise the electric boiler can only obtain power from the distribution grid and therefore network charges and energy taxes have to be paid for electricity usage. Furthermore, in the CHP location scenario the boiler can directly feed the thermal storage. Hence, the Hedensbyn location provides more operational flexibility and will probably yield lower operational cost than the Dalen location.

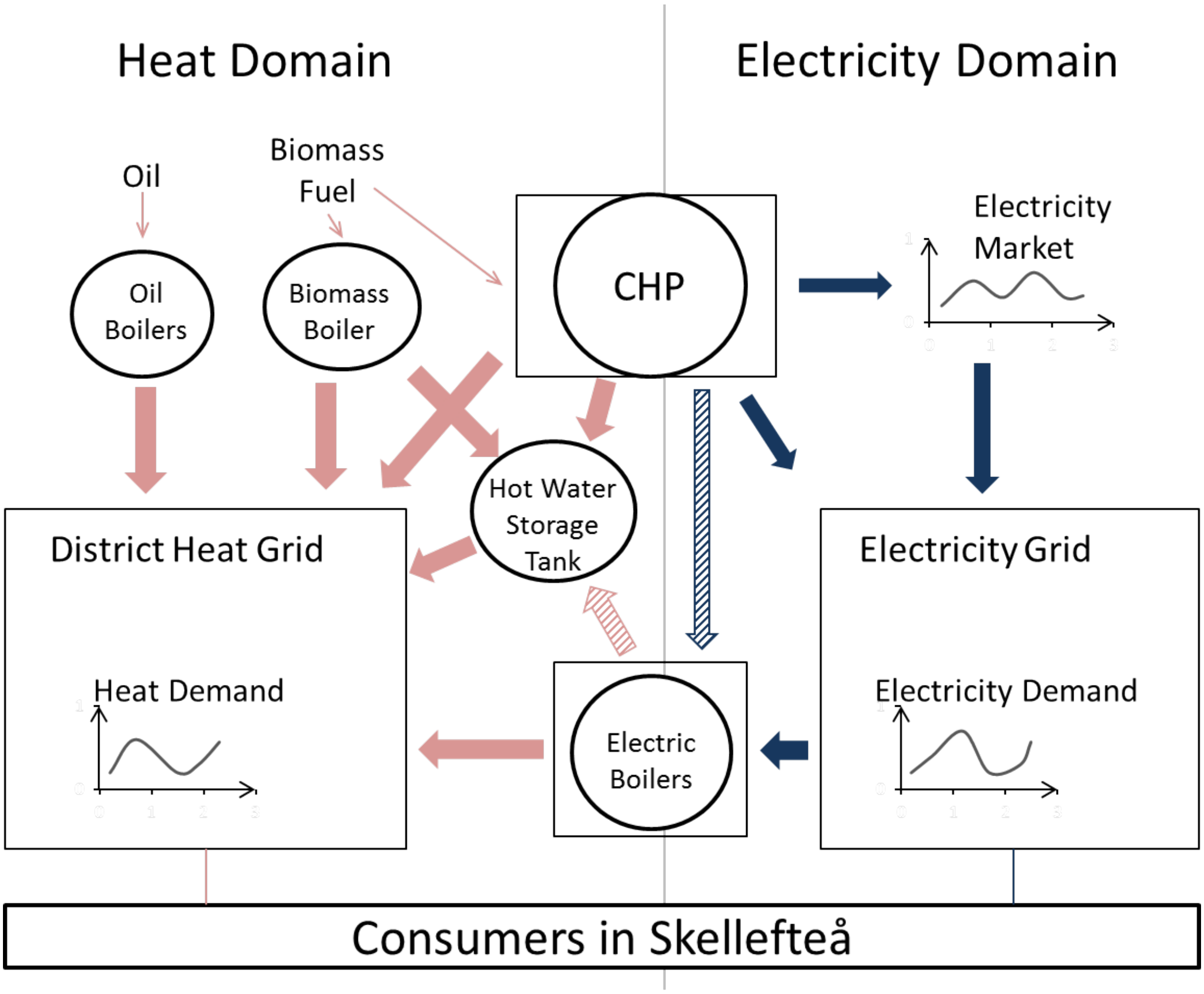

Figure 3: Conceptual overview of scenario set-up for the heat provision of Skellefteå Kraft

- In terms of operational strategy two control strategies are investigated: The ***CostBest*** strategy corresponds to a business model minimizing operational cost and always chooses the cheapest option for heat production. The ***OilOut*** strategy on the other hand uses all other options before operating the oil boilers even if e.g. electricity is more expensive. Thus, this control strategy is related to business models aiming to completely phase out oil usage. A comprehensive description of the control strategies is available in Deliverable D5.3.1 “Evaluation of Control Strategies in the Simulation environment” [3].

Combining all of the above options leads to eight different scenario configurations.

2.2 Economic modelling

The technical implications of an electric boiler operation in the district heating grid of Skellefteå are investigated in detail by the co-simulation environment and presented in Deliverable D4.3.1 [1] and Deliverable D5.3.1 [3]. The investigation of economic long-term effects is based on the formal framework presented in [5] and briefly described in this section:

2.2.1 Mathematical Model:

For the evaluation of the economic effects of an electric boiler investment a linear optimization model has been implemented describing the operation of SKRs power plants over the course of 20 years and minimizing the operational and maintenance (O&M) cost for heat production. Hence, the objective function is defined by the sum of the cost for the operation of each technology subtracted by the revenue from electricity spot market sales:

$$\min \sum_{20\text{ years}} C_{\text{CHP}} + C_{\text{BiomassBoiler}} + C_{\text{OilBoilers}} + C_{\text{ElectricBoiler}} + C_{\text{Storage}} + C_{\text{SpotMarket}} - R_{\text{SpotMarket}} \tag{1}$$

The heat demand of the customers that has to be satisfied is an exogenous parameter. Thus the revenue from retailing cannot be influenced by power plant operation and therefore has been neglected in the objective function. The cost for each for the operation of each power plant consists of the cost for fuel and O&M cost. The cost for the electric boiler and the thermal storage in the objective function only include O&M cost, because the fuel cost are already reflected in the spot market or electricity production cost and the heat production cost respectively. Regarding the electric boiler it has to be differentiated between the scenarios whether network charges and energy tax have to be paid.

The constraints comprise the energy balance constraint, requiring that supply (or in this case heat production) equals demand at each hour, and constraints describing the technological properties of the plants, like the efficiency and the nominal capacity:

$$\begin{gathered} Q_{\text{plant}}^{\text{heatout}} \leq NC_{\text{plant}} \\ Q_{\text{plant}}^{\text{heatout}} = \eta_{\text{plant}} \cdot Q_{\text{plant}}^{\text{fuel}} \end{gathered} \tag{2}$$

According to Deliverable D4.2, Section 4.2 the minimal output of the CHP, the biomass boiler and the oil boilers is 25% and 33% of their nominal capacity, respectively. Hence, binary start-up variables have been introduced and linearized according to the relaxation approach used in [7] The technological parameters are taken from D4.2 and provided by project partners AIT, respectively:

Table 2: Technological parameters for the mathematical model

Technology	Nominal capacity	Efficiency
Hedensbyn biomass CHP	98 MW	0.79
Hedensbyn biomass boiler	25 MW	0.9
Hedensbyn thermal storage	Maximal 60 MW (depending on temperature difference to the district heating grid)	Heat Loss factor based on outdoor temperature provided by WP4

Oil boilers	7×12 MW	0.91
Electric boiler	24 MW / 35 MW	0.99

For the CHP production the relation between heat and power output is fixed by the following equation derived from monitoring data by WP4:

$$CHP^{\text{Heat}} + CHP^{\text{Electricity}} = 1.5987 \cdot CHP^{\text{Heat}} - 5.6687 \tag{3}$$

2.2.2 Model scaling:

The heat demand is modeled based on the sigmoid function presented in [8]. This approach requires data for the outdoor temperature, which is obtained from ERA-Interim (http://apps.ecmwf.int/datasets/data/interim-full-daily/), a global atmospheric reanalysis, as recommended by project partner DLR. For the economic modeling 20 years of historical outdoor temperature data for Skellefteå from 1995 to 2014 has been used to derive the heat demand of SKR's customers.

The initial fuel and electricity prices as well as network charges and taxes are listed in Table 3. They have been chosen according to [9], [10] and experience values of SKR. The maintenance cost of different power plants and the investment cost for electric boilers are taken from [11].

Table 3: Technological parameters for the mathematical model

Fuel type	Price	Network charges	Tax
Biomass	21 EUR/MWh	-	-
Oil	56.30 EUR/MWh	-	15.67 EUR/MWh
Electricity	Hourly NordPool spot market price obtained from http://www.nordpoolspot.com/historical-market-data/	3.38 EUR/MWh	22.73 EUR/MWh

2.2.3 Sensitivity analysis:

In addition to the different scenarios regarding the conceptual set-up a sensitivity analysis is conducted by investigating different parameter development scenarios for the heat demand, the electricity price and the oil price:

- For the ***heat demand*** three different scenarios regarding the total demand increase over the course of 20 years are analyzed: ***+0%***, ***+15%*** and ***+30%***. The demand is assumed to grow incrementally by the same value each year.
- The average yearly ***electricity price*** on the NordPool spot market is assumed to stay the same (***+0%***) or to increase by ***+20%*** totally, corresponding to an annual price increase of 0.92%.
- For the ***oil price*** three variations of the annual price change, -2.52%, +0% and +1.7%, are examined. They correspond to a final price difference of ***-40%***, ***+0%*** and ***+40%***, respectively, after 20 years.

Considering the eight scenario set-ups plus one baseline set-up and the 18 combinations of parameter development scenarios, 162 different scenario configurations are simulated.

From the perspective of an electric boiler investment the worst of the examined price conditions are an oil price decrease of 40% and an electricity price increase of 20%. They are referred as the ***worst-case*** scenario from now. The initial conditions of 0% oil price and 0% electricity price change is referred to as the ***initial*** scenario. Finally an oil price increase of 40% with an unaltered electricity price defines the ***best-case*** scenario.

2.3 Results

Depending on the business model of Skellefteå Kraft the major economic key performance indicators (KPIs) for this case study are the total cost for heat production, the internal rate of return of the electric boiler investment, fossil fuel savings and the reduction of greenhouse gas emissions.

2.3.1 Total cost for heat production

This KPI considers all the costs for heat production that are potentially affected by a new electric boiler investment. This includes all the components of the objective function presented in equation (1). In general, the total cost can be divided into investment cost and operational cost. Here, operational cost comprises the fuel cost for biomass or oil, the cost for electricity purchased on the spot market and the maintenance cost of the power plants. These costs are subtracted by the revenue generated from selling electricity on the spot market.

Table 4: O&M cost change in percent with electric boiler compared to baseline scenario (control strategy: CostBest)

O&M cost change compared to baseline in % with the CostBest strategy					
Demand	Prices	City		CHP	
		24 MW	35 MW	24 MW	35 MW
0%	worst-case	0.30	0.41	0.13	0.24
	initial	0.09	0.20	-0.03	0.07
	best-case	-0.15	-0.05	-0.28	-0.18
30%	worst-case	0.40	0.53	-0.71	-0.73
	initial	-0.43	-0.43	-2.61	-2.90
	best-case	-1.84	-2.08	-4.05	-4.58

Table 4 shows the reduction of operational cost in percent with a new electric boiler compared to the baseline scenario without the electric boiler. Considering that the electric boiler installation provides an additional degree of freedom in heat production the operational costs are expected to decrease. However, operational costs also include maintenance costs for the electric boiler that do not arise in the baseline scenario. Thus, installing an electric boiler can also cause an operational cost increase, in particular in the scenarios without demand increase, when it is barely operated.

For the analysis of the economic implications of an electric boiler installation the investment costs have to be considered as well. Table 5 shows change of total cost in percent also including the electric boiler investment cost. It can be seen clearly that an electric boiler investment would not be very economical in the scenarios without demand increase. This is due to the fact that heat produced from biomass is significantly cheaper than heat produced from oil or electricity and there are only a couple of hours per year, when the electric boiler can be used instead of the oil boiler (see Figure 1). Thus, even in the best-case price constellation the electric boiler cannot generate enough benefits to justify its investment.

Furthermore, both Table 4 and Table 5 clearly show that the Hedensbyn (CHP) site is the better location for the electric boiler installation from an economical point-of-view. The main reason for this has already been mentioned in Section 2.1 and is illustrated in Figure 3: At the CHP location the electric boiler can be operated with the electricity produced from the CHP and, hence, save electricity network charges and the energy tax.

Table 5: Total cost change in percent with electric boiler compared to baseline scenario (control strategy: CostBest)

Total cost change compared to baseline in % with the CostBest strategy					
Demand	Prices	City		CHP	
		24 MW	35 MW	24 MW	35 MW
0%	worst-case	1.41	1.90	1.24	1.72
	initial	1.13	1.59	1.01	1.46
	best-case	0.89	1.34	0.76	1.21
30%	worst-case	1.32	1.76	0.20	0.49
	initial	0.42	0.70	-1.76	-1.76
	best-case	-1.00	-0.96	-3.22	-3.46

2.3.2 Internal rate-of-return of electric boiler investment

The internal rate-of-return is a very meaningful parameter for the economic efficiency of an investment. It is the discount rate that makes the net present value of an investment equal to zero, when considering the benefits generated by the project. In this case the benefits are the annual cost reductions in heat production during the lifetime of the electric boiler, which has been assumed to be 20 years. Table 6 shows the IRR of the electric boiler investment in percent with the CostBest control strategy. Fields with N/A indicate that the benefits in this scenario are too low (or even negative) for the calculation of an IRR, which makes the investment economically very inefficient.

Table 6: Internal rate-of-return (IRR) of the electric boiler investment with the CostBest strategy

IRR of the electric boiler investment in % with the CostBest strategy					
Demand	Prices	City		CHP	
		24 MW	35 MW	24 MW	35 MW
0%	worst-case	N/A	N/A	N/A	N/A
	initial	N/A	N/A	-18.41	N/A
	best-case	-8.52	-12.89	-5.41	-8.98
30%	worst-case	N/A	N/A	1.99	-0.34
	initial	-1.37	-3.02	12.53	10.63
	best-case	8.70	7.27	16.17	14.27

Table 6 again clearly indicates on the one hand that an electric boiler investment is not economical if no demand increase is expected and on the other hand that the CHP site is the preferable location for an electric boiler investment. Furthermore, it can be seen that the smaller electric boiler size generates a better IRR. This is because each additional MW installed gets less hours of operation and, consequently, can generate less economical benefits. Thus each additional MW of capacity is more expensive than the previous one.Table 6: Internal rate-of-return (IRR) of the electric boiler investment with the CostBest strategy

This is also affirmed by Table 7 showing the full-load hours (FLH) of the electric boiler operation. The full-load hours are the yearly output of the electric boiler in MWh divided by its nominal capacity in MW.

Table 7: Full-load hours of the electric boiler with the CostBest strategy

FLH of the electric boiler in with the CostBest strategy					
Demand	Prices	City		CHP	
		24 MW	35 MW	24 MW	35 MW
0%	worst-case	158	110	401	276
	initial	199	138	519	359
	best-case	200	138	519	359
30%	worst-case	301	224	868	640
	initial	639	494	1011	752
	best-case	663	511	1012	753

2.3.3 Fossil fuel savings and reduction of greenhouse gas emissions

Aside from the economic values another set of very important KPIs are related to fuel usage and CO2 emissions. Table 8 and Table 9 show the maximum annual oil share for heat production in percent with the CostBest and the MinOil strategy, respectively.

Table 8: Maximal annual oil share with the electric boiler and the MinOil strategy

Maximal annual oil share in % with the CostBest strategy						
Demand	Prices	StatusQuo	City		CHP	
			24 MW	35 MW	24 MW	35 MW
0%	worst-case	1.62	0.02	0.00	0.02	0.00
	initial	1.58	0.02	0.00	0.02	0.00
	best-case	1.53	0.02	0.00	0.02	0.00
30%	worst-case	10.42	2.02	0.77	2.02	0.77
	initial	10.41	2.02	0.77	2.02	0.77
	best-case	10.40	2.02	0.77	2.02	0.77

Table 9: Maximal annual oil share with the electric boiler and the CostBest strategy

Maximal annual oil share in % with the CostBest strategy						
Demand	Prices	StatusQuo	City		CHP	
			24 MW	35 MW	24 MW	35 MW
0%	worst-case	1.62	1.36	1.36	0.06	0.05
	initial	1.58	0.05	0.05	0.02	0.00
	best-case	1.53	0.03	0.00	0.02	0.00
30%	worst-case	10.42	8.70	8.37	2.26	1.41
	initial	10.41	2.33	1.04	2.03	0.80
	best-case	10.40	2.06	0.79	2.03	0.77

It can be seen in Table 8 that adding an electric boiler can significantly reduce the oil usage for heat production. According to Table 9 the CostBest strategy performs almost as well as the MinOil strategy in the initial and best-case price constellations. However, with the worst-case price conditions the CostBest strategy barely accomplishes an improvement compared to the baseline set-up (StatusQuo) in terms of oil savings. The additional costs for heat production of the MinOil strategy compared to the CostBest strategy in percent are illustrated in Table 10.

Table 10: Additional cost with the MinOil strategy in % compared to the CostBest strategy

Additional cost with MinOil strategy in %					
Demand	Prices	City		CHP	
		24 MW	35 MW	24 MW	35 MW
0%	worst-case	0.21	0.01	0.01	0.03
	initial	0.00	0.00	0.00	0.00
	best-case	0.00	0.00	0.00	0.00
30%	worst-case	1.80	0.11	0.18	0.89
	initial	0.08	0.00	0.00	0.04
	best-case	0.00	0.00	0.00	0.00

In order to calculate the total CO2 emissions the fuel emission factor of oil and of electricity in Sweden taken from [12] and [13] have been used. It has to be mentioned here that due to the high share of nuclear and hydropower in Sweden's electricity generation its CO2 emission factor is comparatively low. Thus, a power-to-heat approach can better help to reduce CO2 emissions than in countries using more fossil fuels for electricity production. Table 11 shows the CO2 emissions in t caused by heat production over the course of 20 years with the CostBest control strategy.

Table 11: CO2 emissions in t caused by heat production over the course of 20 years with the CostBest control strategy

CO2 emissions in t over the course of 20 years with the CostBest control strategy						
Demand	Prices	StatusQuo	City		CHP	
			24 MW	35 MW	24 MW	35 MW
0%	worst-case	14599	6841	6739	3818	3727
	initial	14043	1523	1413	4953	4899
	best-case	13737	1408	1309	4953	4899
30%	worst-case	94305	68718	65522	28184	20180
	initial	93470	25860	15420	26424	16357
	best-case	93134	23018	12331	26361	16164

2.4 Conclusions and recommendations

The recommendations depend very much on the business model or objective pursued by Skellefteå Kraft.

- If the primary goal is ***reducing oil usage***, this can be achieved best with biggest electric boiler size and the MinOil strategy regardless of the electric boiler location. In the scenarios without demand increase, this way almost a complete oil phase-out can be achieved.
- However, from an economic perspective an investment in a smaller electric boiler would be more efficient, because a smaller boiler gets more full-load hours of operation and generates a higher internal rate-of-return.
- If ***reducing cost for heat production*** is the only targeted business model an electric boiler investment is not advisable, because in the scenarios without demand increase each configuration results in higher total cost.
- However, an electric boiler investment would be a reasonable option to ***prepare for demand increase***. Here, the CHP location is recommended, because it yields cheaper operation and a higher internal rate-of-return. Even though an electric boiler installation is beneficial in most price constellations, its economic efficiency is very sensitive regarding the fuel price development.
- In general it can be concluded, that the Hedensbyn site is the preferable location for an electric boiler investment. It is more cost-efficient, because the electric boiler can be operated with electricity produced by the CHP, which is free from network charges and the energy tax.
- Furthermore, additional benefit could be generated by electric boilers on other markets like the balancing market. However, this has not been investigated in detail in this case study.

2.5 Further investigations

2.5.1 Both electric boiler locations

During the investigations of the first scenario in Skellefteå, project partner SKR started operating the electric boiler at the Dalen site that has already been installed but has not been used yet. The OrPHEuS results of the first scenario, however, indicated that the Hedensbyn site is the preferable location in terms of economic benefits and additional flexibility. Thus, further scenarios are analysed in economic terms only by WP2. In these scenarios the baseline is given by the results of the configuration with a ***24 MW*** electric boiler installed at the ***City*** location and from now on referred to as ***CitySQ***. It is investigated, whether installing an additional electric boiler at the Hedensbyn yields extra benefits in terms of cost or CO_2 emissions. For the new additional electric boiler three different sizes are considered: ***11 MW***, ***24 MW*** and ***35 MW***. For the rest, the same demand, price and control strategy variations are investigated as in the first scenario.

Table 12: Change of total cost for heat production in %

Change in total cost for heat production in %								
Demand	Prices	CostBest			MinOil		
		11 MW	24 MW	35 MW	11 MW	24 MW	35 MW
0%	worst-case	0.58	1.14	1.63	0.61	1.15	1.64
	initial	0.54	1.04	1.50	0.54	1.04	1.50
	best-case	0.53	1.04	1.50	0.53	1.04	1.50
30%	worst-case	-0.07	0.11	0.42	0.82	0.53	0.64
	initial	-0.94	-1.33	-1.23	-0.90	-1.32	-1.23
	best-case	-1.22	-1.74	-1.67	-1.22	-1.74	-1.67

Table 12 shows the change of total cost in % compared to the scenario with only the 24 MW electric boiler installed at the Dalen (City) site. It is important to mention that the results using the CostBest control strategy here are compared to the ***CitySQ*** CostBest results and, analogously, the MinOil results are compared to the ***CitySQ*** MinOil results. Therefore, the CostBest and the MinOil numbers look rather similar. Of course, the total costs of the MinOil strategy are, in general, higher. Here, again the smaller electric boiler size seems more economically efficient. Interestingly, the 24 MW electric boiler provides the highest cost reduction in two of the three demand increase scenarios.

Table 13: Internal rate-of-return in % of the additional electric boiler investment at the Hedensbyn site

IRR in %							
Demand	Prices	CostBest			MinOil		
		11 MW	24 MW	35 MW	11 MW	24 MW	35 MW
0%	worst-case	N/A	N/A	N/A	N/A	N/A	N/A
	initial	-12.58	N/A	N/A	-12.58	N/A	N/A
	best-case	-11.95	N/A	N/A	-11.95	N/A	N/A
30%	worst-case	5.84	3.23	0.43	N/A	N/A	-3.11
	initial	12.41	10.79	8.80	12.18	10.74	8.81
	best-case	13.72	12.00	9.99	13.72	12.00	9.99

Table 13, however, shows that the smallest electric boiler investment has the highest internal rate-of-return in all scenarios. The internal rate-of-return is calculated by comparing CostBest results to the CitySQ CostBest results the MinOil results to CitySQ CostBest results.

The maximal annual oil share for heat production in % is shown in Table 13 for different scenarios and control strategies. The additional 11 MW electric boiler is sufficient to achieve a phase-out of oil usage if no demand increase is expected. If a demand increase of 30% is expected phasing out oil can be almost achieved with the biggest oil boiler size.

Table 14: Maximal annual oil share in %

Maximal annual oil share								
Demand	Prices	CitySQ	CostBest			MinOil		
			11 MW	24 MW	35 MW	11 MW	24 MW	35 MW
0%	worst-case	1.36	0.32	0.32	0.32	0.00	0.00	0.00
	initial	0.05	0.00	0.00	0.00	0.00	0.00	0.00
	best-case	0.03	0.00	0.00	0.00	0.00	0.00	0.00
30%	worst-case	8.70	4.27	4.11	4.10	0.77	0.14	0.01
	initial	2.33	0.94	0.46	0.43	0.77	0.14	0.01
	best-case	2.06	0.78	0.14	0.01	0.77	0.14	0.01

In general, this further investigation confirms the conclusions of the primary case study and shows again that the economic efficiency of an electric boiler investment very much depends on the expected heat demand development of SKR's customers.

2.5.2 Considering batteries

Another interesting question arises during the investigation of the primary case study. Would electric boilers perform better in combination with electric storage devices? In order to analyse this, a further scenario based on the scenario from section 2.5.1 is developed and investigated using the economic model. Instead of the additional electric boiler at the Hedensbyn site, 10 additional distributed hybrid stations are installed in the district heating system of SKR. These stations can consist of the following technologies:

- 1 MW electric boiler
- 10 m^3 hot water storage tank
- 1 MW battery with 1 MWh

Different configurations of the hybrid stations are examined so that the economic effects of each technology on the heat production of SKR can be deduced:

- ***StatusQuo***: No distributed hybrid stations are considered. This is the scenario with the 24 MW electric boiler installed at the Dalen site.
- ***DistBoil***: Distributed electric boilers are installed in additionally.
- ***DistTES***: Distributed electric boilers and hot water storage tanks are installed additionally.
- ***DistBat***: Distributed electric boilers and batteries are installed additionally.
- ***DistAll***: All of the above technologies are installed additionally in the distributed stations.

Furthermore it is differentiated between two different control strategies with respect to the battery operation: The ***Flex*** control strategy uses batteries only to increase flexibility of operation of the hybrid substations. In contrast, the ***Trade*** control strategy allows the usage of batteries for arbitrage on the spot market.

Table 15: Oil Share and annual cost of the different scenarios with the Flex control strategy and low demand

Flex	OilShare	Cost	Cost difference in EUR compared to …			
	[%]	[EUR]	StatusQuo	DistBoil	DistTES	DistBat
StatusQuo	0.00	11731100.56				
DistBoil	0.00	11740051.70	8951.14			
DistTES	0.00	11739528.53	8427.97	-523.17		
DistBat	0.00	11738291.19	7190.63	-1760.51	-1237.34	
DistAll	0.00	11737848.69	6748.13	-2203.01	-1679.84	-442.50

The oil share and the annual cost for heat production with the different technology configurations at the distributed stations are shown in Table 15 for the Flex control strategy with low demand (0 % increase). Since the ***StatusQuo*** scenario already results in an oil-free scenario for low demand the distributed electric boilers are not necessary and would be barely operated. However, they still have to be maintained and, thus, all scenarios with distributed stations bring about higher annual cost for heat production than the ***StatusQuo*** scenario, as can be seen in the blue coloured cells of Table 15. The benefits of adding batteries to the distributed stations can be deduced by comparing the ***DistBat*** to the ***DistBoil*** scenario and the ***DistAll*** to the ***DistTES*** scenario, respectively. They are shown in the green fields of Table 15 and amount to approximately 1700 EUR. If an interest rate of 5 % and a battery lifetime of 10 years is assumed, the maximum investment cost for the batteries to be economically efficient is about 1300 EUR/MW or 1.3 EUR/kW. The annual benefit of distributed thermal energy storages can be read from the red marked cells.

Table 16 and Table 17 show the annual oil share and cost for heat production with different technology configurations at the distributed stations with high demand (30 % increase) for the ***Flex*** and the ***Trade*** control strategy, respectively. Here, the distributed hybrid stations achieve both, a cost and oil share reduction. The annual benefits of adding 10 MW of distributed electric boilers are approximately 100000 EUR. This allows maximal investment cost of 124000 EUR/MW if a technical lifetime of 20 years and an interest rate of 5 % is assumed. Adding distributed hot water storages reduces annual cost by roughly 2900 EUR. Depending on the control strategy, installing batteries yields a yearly cost reduction of about 5300 EUR or 7100 EUR, respectively.

Table 16: Oil Share and annual cost of the different scenarios with the Flex control strategy and high demand

Flex	OilShare	Cost	Cost difference in EUR compared to …			
	[%]	[EUR]	StatusQuo	DistBoil	DistTES	DistBat
StatusQuo	1.50	16224309.35				
DistBoil	0.66	16126061.44	-98247.91			
DistTES	0.66	16123034.50	-101274.85	-3026.94		
DistBat	0.66	16120617.38	-103691.97	-5444.06	-2417.12	
DistAll	0.66	16117851.58	-106457.77	-8209.86	-5182.92	-2765.80

Table 17: Oil Share and annual cost of the different scenarios with the Trade control strategy and high demand

Trade	OilShare	Cost	Cost difference in EUR compared to …			
	[%]	[EUR]	StatusQuo	DistBoil	DistTES	DistBat
StatusQuo	1.50	16224309.35				
DistBoil	0.66	16126061.44	-98247.91			
DistTES	0.66	16123034.50	-101274.85	-3026.94		
DistBat	0.66	16118805.94	-105503.41	-7255.50	-4228.56	
DistAll	0.66	16116037.55	-108271.80	-10023.89	-6996.95	-2768.39

Table 18: Maximal economically efficient investment cost of distributed technologies in different scenarios compared to actual investment cost.

			Electric boiler	Hot water storage	Battery
			[EUR/MW]	[EUR/m³]	[EUR/kW]
Actual investment cost			130000 - 160000	260 - 4000	1000 - 1500
Maximal economic investment cost	Low Demand	***Flex***	-	60	1.3
		Trade	-	60	3
	High Demand	***Flex***	124000	360	4
		Trade	124000	360	5.5

Table 18 shows the maximal annual investment cost for the technologies at the distributed stations in different demand and control strategy scenarios. For the calculation an interest rate of 5 % and a technological lifetime of 20 years for the electric boilers and the thermal storages and 10 years for the batteries are assumed. Furthermore, the actual investment cost of these technologies based on the information provided in [11] is listed in Table 18. Clearly, none of the investigated de-centralized technologies is economically efficient in the low demand scenarios. When high demand is assumed, the distributed electric boiler investment could almost be economical. The reason, why this configuration is not as economical as for instance an additional 11 MW electric boiler investment at the CHP site, is the higher specific investment cost of the smaller de-centralized boilers. Adding thermal energy storages to the distributed stations could be beneficial at the lower end of the (very wide-spread) range of actual investment cost. However, batteries are far from economically efficient in all configurations and scenarios with a factor of 200 to 1000 between maximal economical and actual investment cost.

2.5.3 Flexible CHP output

In all preceding investigations a fixed relation between electricity and heat output of the Hedensbyn CHP, as described in Equation (3) in Section 2.2.1, has been assumed. This corresponds to the maximal electricity share for a certain fuel input and it has been fixed because in general electricity is supposed to be more valuable than heat. However, it is also possible to produce a higher share of heat. This can be modelled by relaxing Equation (3) to:

$$CHP^{\text{Heat}} + CHP^{\text{Electricity}} \leq 1.5987 \cdot CHP^{\text{Heat}} - 5.6687 \tag{4}$$

The additional flexibility could be useful during times of high heat demand and low electricity prices. Those are exactly the hours when the electric boilers would be activated. Thus, using this additional flexibility of the CHP would further decrease the full-load hours of the electric boilers and make their investment less beneficial. However, the additional flexibility also facilitates a total cost reduction and a reduction of the maximal annual oil share. Table 19 shows the cost reduction in percent when using the additional flexibility compared to a fixed output ratio for different price and demand scenarios and e-boiler configurations. The respective oil share reduction in percentage points is listed in Table 20.

Table 19: Cost reduction in percent with flexible power-heat output ratio of the Hedensbyn CHP

Demand	Prices	Baseline	City				CHP			
			24 MW		35 MW		24 MW		35 MW	
			CostBest	MinOil	CostBest	MinOil	CostBest	MinOil	CostBest	MinOil
0%	worst	-1.13	-1.17	-1.38	-1.17	-1.37	-1.00	-1.01	-1.00	-1.00
	initial	-1.56	-1.41	-1.41	-1.40	-1.40	-1.28	-1.28	-1.28	-1.28
	best	-1.80	-1.41	-1.41	-1.40	-1.40	-1.28	-1.28	-1.28	-1.28
30%	worst	-3.23	-3.38	-4.70	-3.41	-4.92	-2.30	-2.18	-2.18	-2.13
	initial	-5.53	-4.99	-5.09	-4.90	-4.97	-2.87	-2.86	-2.48	-2.48
	best	-7.11	-5.40	-5.42	-5.08	-5.08	-3.22	-3.22	-2.60	-2.60

Table 20: Reduction of maximal annual oil share in percentage points with flexible power-heat output ratio of the Hedensbyn CHP

Demand	Prices	Baseline	City				CHP			
			24 MW		35 MW		24 MW		35 MW	
			CostBest	MinOil	CostBest	MinOil	CostBest	MinOil	CostBest	MinOil
0%	worst	-1.58	-1.31	-0.02	-1.31	0.00	-0.02	-0.02	-0.01	0.00
	initial	-1.58	-0.05	-0.02	-0.05	0.00	-0.02	-0.02	0.00	0.00
	best	-1.53	-0.03	-0.02	0.00	0.00	-0.02	-0.02	0.00	0.00
30%	worst	-9.04	-7.37	-1.99	-7.04	-0.77	-0.93	-1.99	-0.08	-0.77
	initial	-9.36	-2.21	-1.99	-0.93	-0.77	-1.91	-1.99	-0.68	-0.77
	best	-9.35	-2.03	-1.99	-0.79	-0.77	-2.00	-1.99	-0.77	-0.77

3 Today's scenario in Ulm

The today's scenario in the demonstration site in Ulm addresses the issue of further PV system installations by the customers of local distribution system operator (DSO) and OrPHEuS project partner Stadtwerke Ulm Netze. It is motivated by both, use case 3 "Optimal asset management and extension planning of distribution grids" and use case 4 "Maximizing local consumption of remote self-generation", which are comprehensively described in Deliverable D2.3 [6]. The use case examines a hybrid cooperative business model for the usage of PV surplus for domestic hot water as an alternative to transformer and grid reinforcements.

3.1 Scenario and business model description

In the demonstration site Einsingen in the city of Ulm, Germany, there are currently 135 households with a combined yearly electricity demand of almost 1 GWh. Furthermore, there are 21 PV systems installed with a total nominal capacity of 233 kW, which produce approximately 230 MWh of electricity per year. OrPHEuS project partner and local DSO Stadtwerke Ulm Netze (SWU) is expecting the number of PV systems owned by their customers to significantly increase in the following years. This means that the distribution grid would have to take a lot of PV surplus during sunny hours. Figure 4 shows the yearly load duration curve of the 0.63 MVA MV/LV transformer in Einsingen for different PV installation scenarios, created by project partner Hochschule Ulm (HSU) based on a rooftop potential analysis. The current situation is indicated by the ***PVSQ*** scenario. The other scenarios (***PV50***, ***PV75*** and ***PV100***) show that the transformer is not able to take the entire PV surplus.

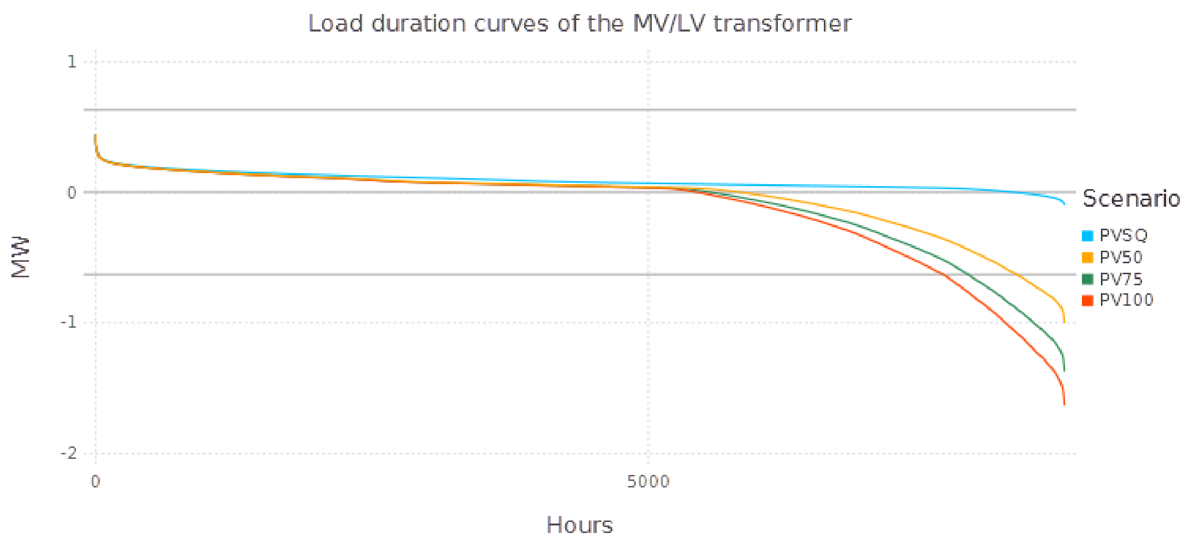

Figure 4: Load duration curves of the MV/LV transformer in Einsingen for different PV installation scenarios

In order to prepare for this situation there are in general three options:

1. ***Do nothing***: In this case PV generation during peak production hours has to be shed and the respective energy is lost. This energy corresponds to the area between the negative transformer rating line and the load duration curve of the respective PV scenario in Figure 4. It is subject to the regulatory framework, whether the DSO has to financially compensate the customers for the energy, they could have otherwise sold on the spot market[1].
2. ***Grid reinforcement***: The DSO invests in a more powerful transformer capable of taking all the PV surplus of the customers in the LV network branch. This would set the lower (grey) transformer rating line in Figure 4 further down and reduce the area of lost PV surplus energy. A transformer rating of 1.6 MVA would be sufficient to take almost all PV feed-in even in the ***PV100*** scenario.
3. ***Local usage***: The PV surplus is used locally preventing the need for a new transformer and the shedding of energy.

In general, there are many different possibilities for the third option. However, the DSO, who would benefit most from increasing local usage and thus avoiding transformer reinvestments, can barely influence it. PV customers, on the other hand, may not be interested in increasing their local usage, if they could just sell their energy surplus alternatively.

In this case study a hybrid cooperative business model possibility for the DSO to increase local usage of PV surplus is investigated. The idea is that SWU invests in small electric heating rods in the hot water storages of their customers. These heating rods are remotely controlled by the DSO and activated according to different control strategies when PV surplus is available. This way the feed-in from the LV to the MV grid can be reduced, the local usage of PV surplus can be increased and fuels for the alternate hot water heating system (gas, oil or biomass) can be saved.

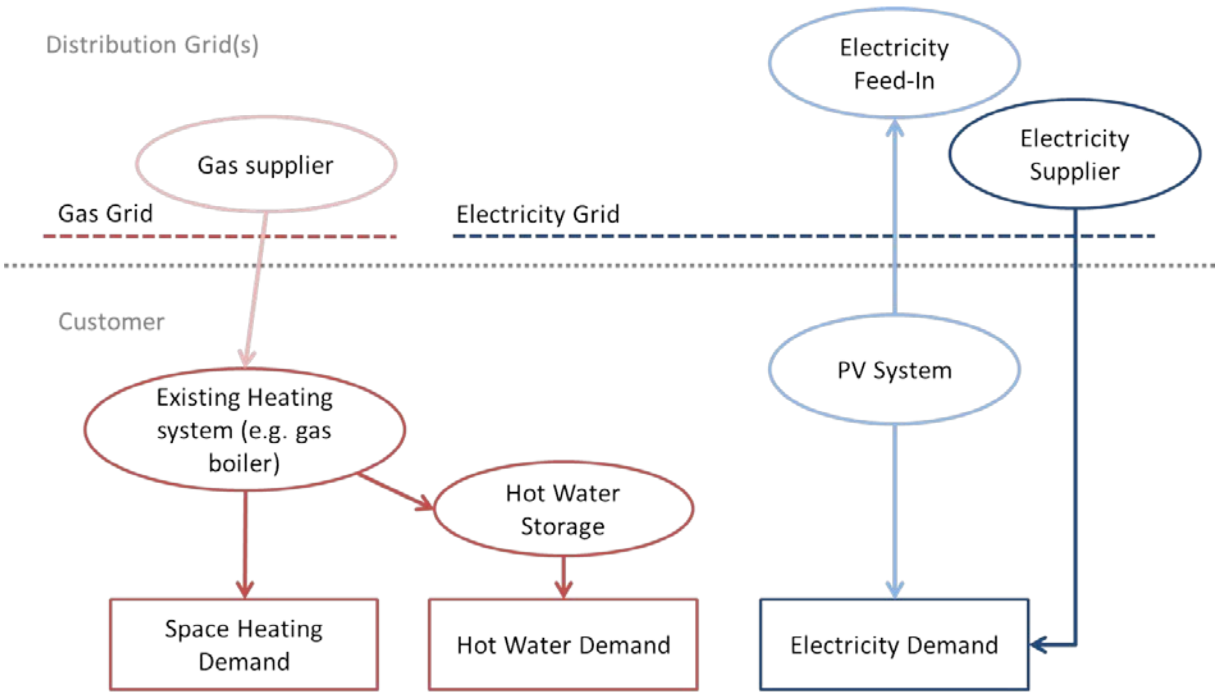

Figure 5: Conceptual overview of a customer's energy supply in the current situation

[1] Currently, customers with PV systems are granted a fixed feed-in tariff for excess generation. However, this subsidy is decreasing each year and hence the electricity fed into the grid is valued with the spot market price in this case study.

The concept of the business model is illustrated in Figure 5 and Figure 6. Figure 5 shows the concept of customers' energy supply in the current situation. They can purchase electricity from their supplier and obtain it via the distribution network. Optionally they can also own a PV system to partly satisfy their electricity demand. When it is sunny and too much electricity is produced, the surplus is fed into the grid. In addition, to satisfy their heat demand they have a heating system fired by natural gas, oil or biomass. If it is fired by natural gas, they are connected to the gas distribution grid. This heating system is used for space heating and it also heats a hot water storage for domestic hot water. The heating and the electricity domain are not connected and independent from each other.

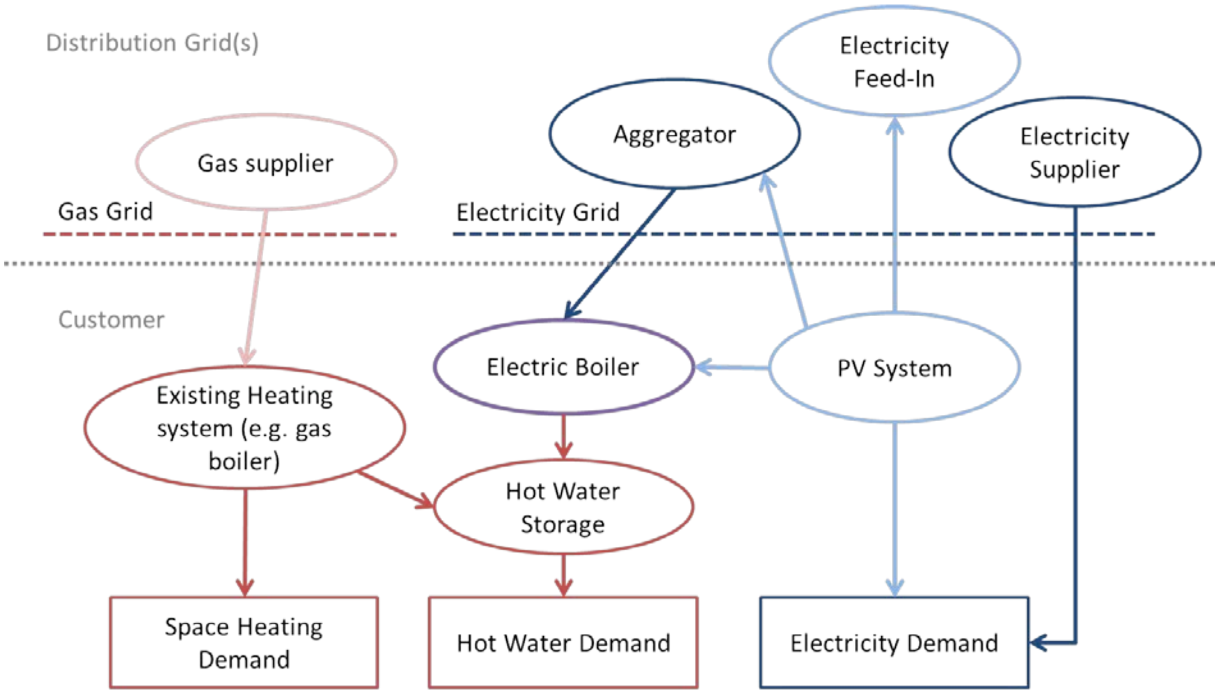

Figure 6: Conceptual overview of a customer's energy supply with the DSOs hybrid cooperative business model implemented. Here the DSO plays the role of the aggregator.

Figure 6 illustrates the concept of customers' energy procurement with the new hybrid cooperative business model. Electric boilers are installed at the customers' homes by the DSO and operated using different control strategies based on the following idea. If electricity production of PV customers exceeds their demand and the hot water storage can be charged, the electric boiler is switched on to reduce the residual feed-in. If the customers' storage is fully charged or additional surplus remains, the aggregator - in this case the DSO – starts the electric boilers of other customers (with or without PV systems) in the low voltage network branch to reduce the feed-in into the medium voltage network. On balance sheet this means that the PV customer is selling PV surplus to the aggregator, who then retailing it to another customer for electric boiler operation. This way at each customer's house a hybrid coupling point has been introduced which can help to reduce electricity grid voltage violations and transformer loading and at the same time save fuel that else would have been used for hot water heating.

The DSO's electricity network operation is supposed to benefit from this hybrid cooperative business model. Thus it is assumed that no grid tariff is charged for the interactions between customers and the aggregator, i.e. for the operation of the electric boilers. Otherwise, from a customer's point-of-view, it would be cheaper to use the existing heating system for domestic hot water heating than the electric boiler in most cases.

3.2 Economic modelling

Different operational control strategies with or without meteorological predictions are developed by WP5 and described and evaluated in Deliverable D5.3.1 [3]. Technical implications of different control strategies on the network and key parameters like the voltage violation are investigated by the Co-Simulation environment in WP4 and presented in Deliverable D4.3.1 [1]. The economic investigations made assume an optimal control strategy with perfect foresight and rather focus on the implications of the business model for different market participants.

3.2.1 Mathematical Model

The MATLAB model developed for this investigation is based on the methods for customer models presented in the formal framework in Deliverable D2.2 [5]. It is a linear optimization model minimizing the total cost of the customers' energy procurement considering one year in a quarter-hourly temporal resolution. As indicated in Figure 6, the newly installed electric boiler for hot water heating can either be operated with PV surplus or with electricity obtained from the Aggregator (DSO), if at the same time another customer is offering PV surplus via the Aggregator. Since the aggregator does not use any battery devices and is only coordinating the customers' electric boiler operation with PV surplus on balance sheet, the total surplus sold to the aggregator and the total electricity bought by the customers have to coincide at each time step:

$$\sum_{\text{Customers}} Q_{\text{BuyFromAggregator}} = \sum_{\text{Customers}} Q_{\text{SellToAggregator}}. \tag{5}$$

Based on the benefits generated by the electric boilers and the cooperative control or the new transformer respectively, maximum investment cost for the heating rods or a more powerful transformer are deduced in the post-processing of the model results.

3.2.2 Model Scaling

Data for existing heating systems, heat and electricity demand and different PV installation scenarios are provided by project partner HSU. Quarter-hourly load profiles for electricity and domestic hot water are generated from the synthetic load profiles available at [14]. They are randomized and scaled to the respective annual demand. The assumed efficiencies for the heating systems are listed in Table 21. The nominal capacity of each heating system varies depending on the building's area and the annual heat demand of the customers.

Table 21: Efficiencies of different heating systems

Heating system	Efficiency
Electric boiler (heating rod)	0.99
Gas boiler	0.9
Oil boiler	0.75
Biomass boiler	0.85

Data for customer tariffs are taken from the website of Stadtwerke Ulm [15], [16] and fuel costs are based on the information provided in [17] and [18], respectively. They are listed in Table 22.

Table 22: Customer tariffs and fuel prices assumed for economic modeling

Fuel	Price component	Variable [ct/kWh]	Fixed [EUR/year]
Electricity	Supplier tariff	7.941	9.44
	Network charges	4.26	82.06
	Fees	11.257	0
	Total	**23.458**	**91.5**
Natural gas	Supplier tariff	3.728	12.56
	Network charges	1.498	33.46
	Fees	1.564	0
	Total	**6.79**	**46.02**
Heating Oil	Price	4.073	0
	Fees	0.614	0
	Total	**4.687**	**0**
Biomass	**Total**	**3.87**	**0**

3.2.3 Sensitivity analyses

Table 23 shows the different parameter variations that are considered by the economic model. This yields a total of 16 different configurations for the model that optimizes the energy procurement of 135 customers over one year on a quarter-hourly level.

Table 23: Parameter variation scenarios considered by the economic model

Parameter	Variations			
Domestic electric boiler size	***1 kW***		***2 kW***	
Domestic hot water storage volume	***100%*** (of existing storage volume)		***200%*** (of existing storage volume)	
PV installation scenario	***PVSQ*** (233 kWp)	***PV50*** (1385 kWp)	***PV75*** (1853 kWp)	***PV100*** (2183 kWp)

3.3 Results

The detailed technical co-simulation results and the evaluation of the relevant technical KPIs, like the impact of control strategies on the voltage in critical network nodes, are presented in Deliverable D5.3.1 [3] and Deliverable D4.3.1 [1], respectively. This section presents the most relevant economic KPIs for this case study.

Figure 7 shows the annual benefit generated by the cooperative hybrid business model for different PV scenarios and different technology configurations. This benefit results from the common cost savings of all customers due to reduced gas, oil and biomass usage as well as a decrease in PV curtailment. The annual cost savings amount to 10000 to 15000 EUR in the PV expansion scenarios. The best technological configuration is given by the set-up consisting of a 2 kW electric boiler and 200 % storage size. However, using the 100 % storage size is only slightly inferior and significantly more realistic than replacing the hot water tanks in all households. Project partners Stadtwerke Ulm Netze GmbH (SWU) and Hochschule Ulm (HSU) are most interested in the ***PV75*** scenario. Thus, for a detailed economic analysis the PV75 scenario and the set-up with 2 kW electric boilers and 100 % storage size are focused on in the following.

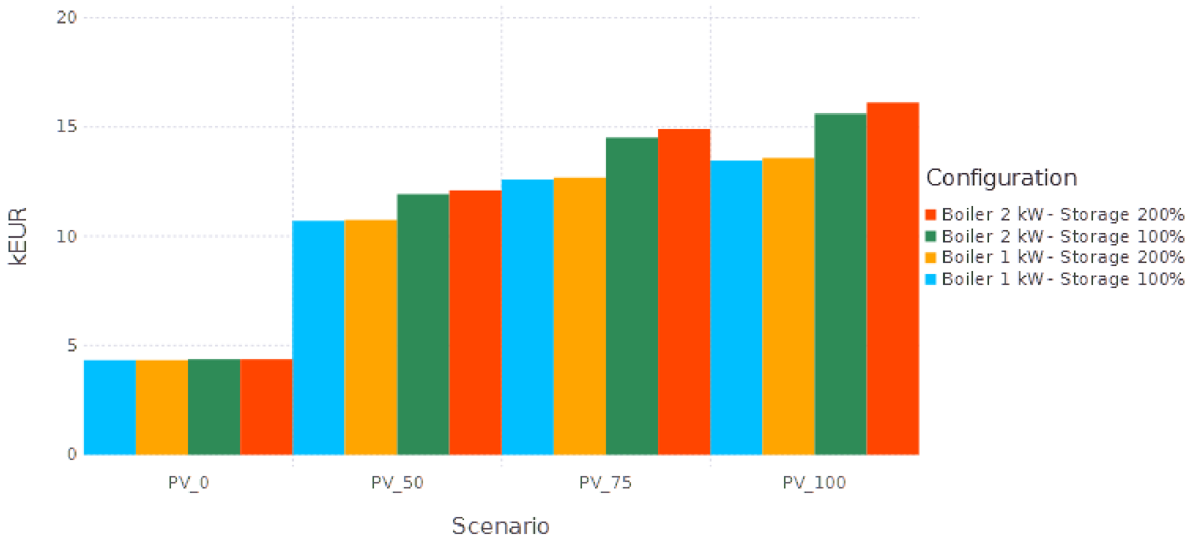

Figure 7: Common annual benefit of all customers generated by the cooperative business model for different PV scenarios and different technical configurations.

3.3.1 Fossil fuel savings and reduction of green-house-gas emissions

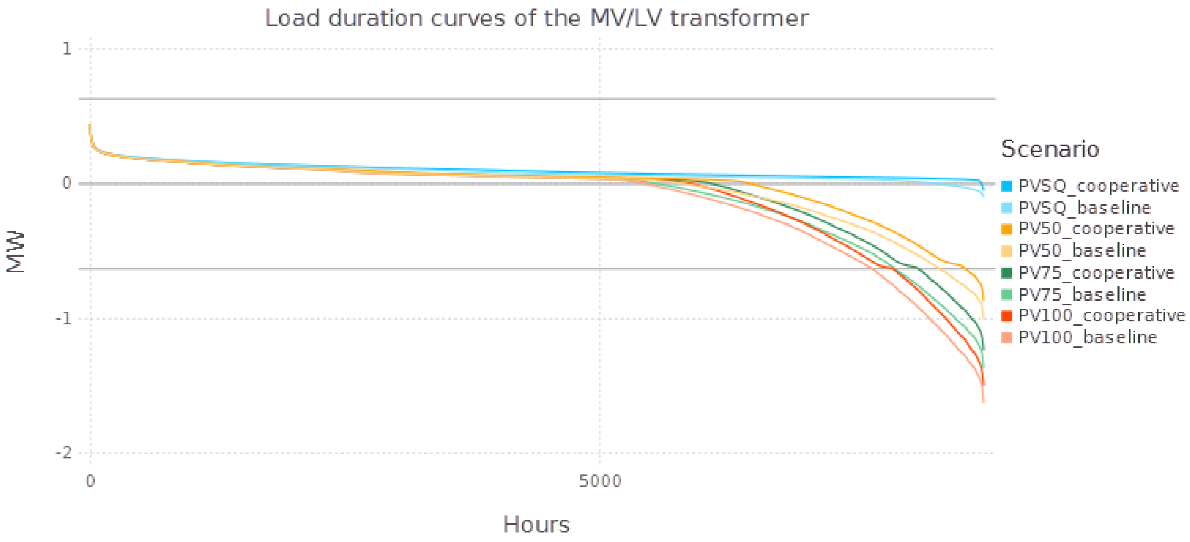

Figure 8: Load duration curves of the MV/LV transformer in Einsingen for different PV installation scenarios with the cooperative hybrid business model

The load duration curves after the implementation of the cooperative hybrid business model compared to the initial load duration curves can be seen in Figure 8 for different PV installation scenarios. The total annual feed-in to the medium voltage network corresponds to the area upper-bound by the zero-axis and lower-bound by the negative part of the load duration curve and the transformer rating line (the lower grey line at -0.63). The triangular area below the transformer rating and above the load duration curve at the bottom right corresponds to the yearly curtailed energy. Both can be significantly reduced with the implementation of the cooperative hybrid business model.

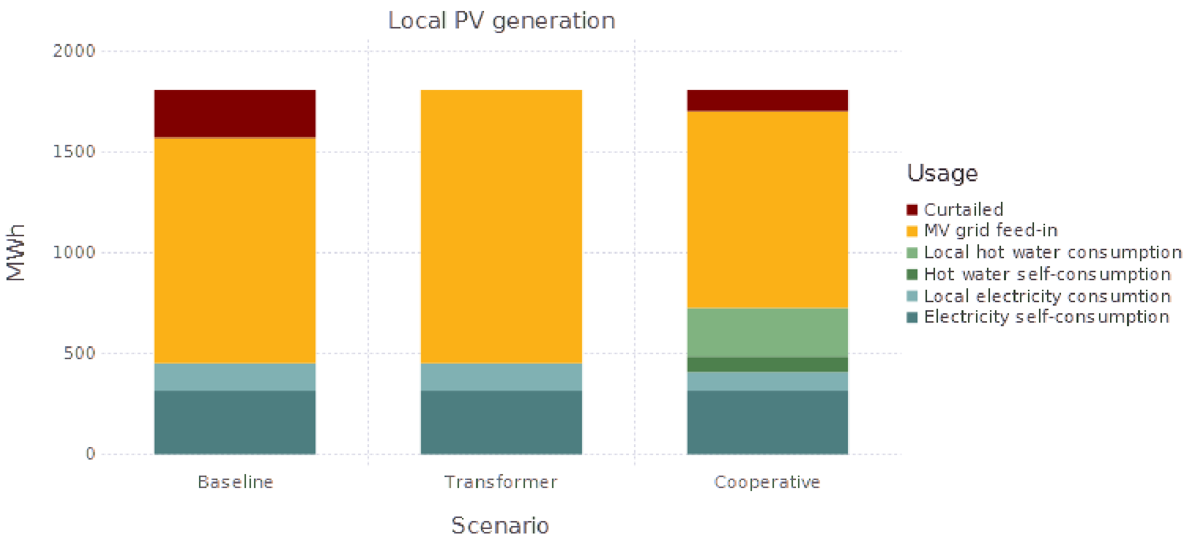

Figure 9: Annual usage of local PV generation in different business models with the PV75 scenario.

Figure 9 shows how the energy produced from local PV systems is used in different business models. In all scenarios about 315 MWh are used for individual self-consumption at household level. This reduces the residual loads of the customers with PV systems and can be interpreted as energy saving measure from their point-of-view. In the baseline scenario another 1.5 GWh are fed in the low voltage electricity network, whereof 135 MWh are used locally and 1120 MWh are injected in the medium voltage network. Note that this corresponds to physical power flows and not to market interactions on balance sheet. About 240 MWh of PV generation have to be curtailed, because transformers capacity limit is reached during several hours. If, however, a more powerful transformer (1.6 MVA) is available, this amount of PV production could also be fed in the medium voltage network. With the installation of electric boilers and the implementation of the hybrid cooperative business model the local usage of PV surplus can be significantly increased. About 80 MWh of electricity can be used for domestic hot water heating directly at household level of the PV customers and another 240 MWh are used at local level by switching on neighbouring electric boilers. This reduces the medium voltage network feed-in to 975 MWh. However, the cooperative business model is not able handle PV surplus at all times and there are still 105 MWh that have to be curtailed.

In addition to increasing the local usage of self-generation the implementation of the cooperative hybrid business model also results in the reduction of (fossil) fuel usage, namely for domestic hot water heating. Figure 10 shows the annual fuel usage for domestic hot water heating in the baseline scenario and with the novel cooperative business model. In total, 223 MWh of natural gas, 97 MWh of heating oil and 12 MWh of biomass can be saved per year. Using the fuel emission factors of [12] this translates to 71 tons of CO_2, 1.8 tons of CH_4 and 0.3 tons of N_2O per year.

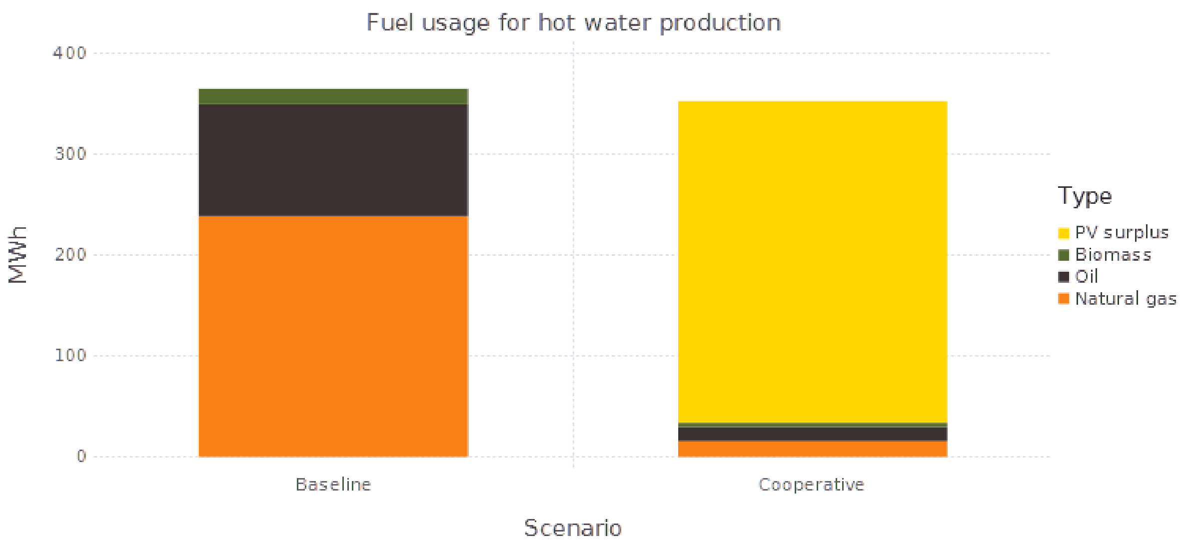

Figure 10: Domestic hot water heating by fuel source in the PV75 scenario.

3.3.2 Cost

Besides environmental considerations such as fossil fuel savings, economic parameters are crucial for the development of a business model. Here, the costs of all households in Einsingen for energy procurement are considered. These include network and supplier tariffs for electricity and for natural gas, the costs for heating oil and biomass as well as fees and taxes. Figure 11 shows the annual cost for energy procurement by component and the revenue from PV feed-in in the PV75 scenario with the baseline business model. The total annual cost of all customers in the baseline scenario amount to approximately 360000 EUR.

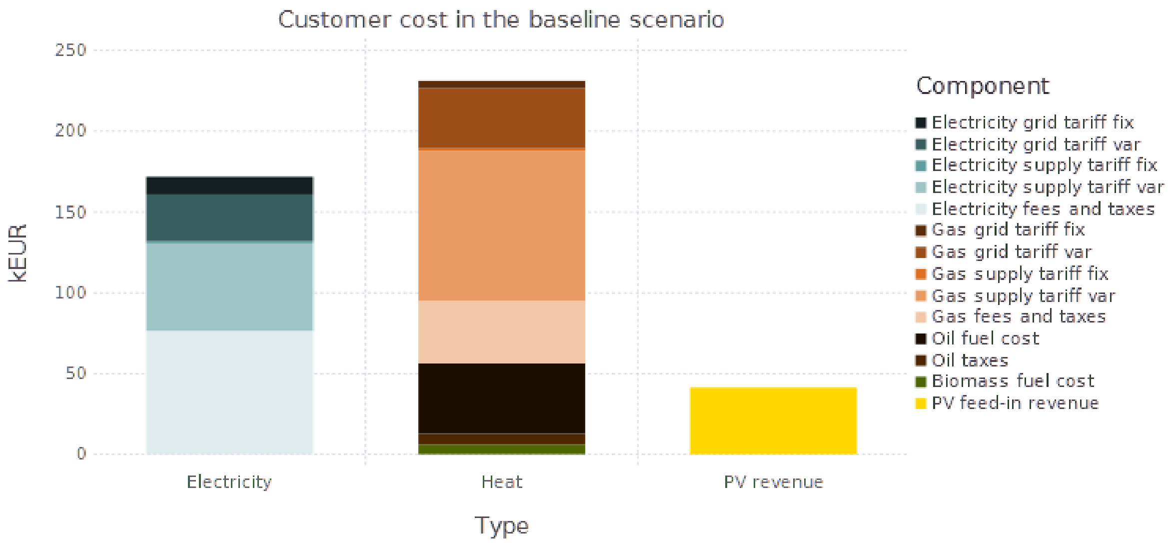

Figure 11: Aggregated annual cost for energy procurement and PV feed-in revenue of all customers in the baseline scenario.

Domestic PV system owners in Germany currently receive a feed-in remuneration of about 12 ct/kWh. However, this value is expected to decrease in the following years [19]. Thus, no fixed feed-in remuneration is assumed here. Instead, the energy generated by PV systems and fed into the electricity grid (and also the electricity lost due to curtailment) is valued with the German spot market prices from 2015.

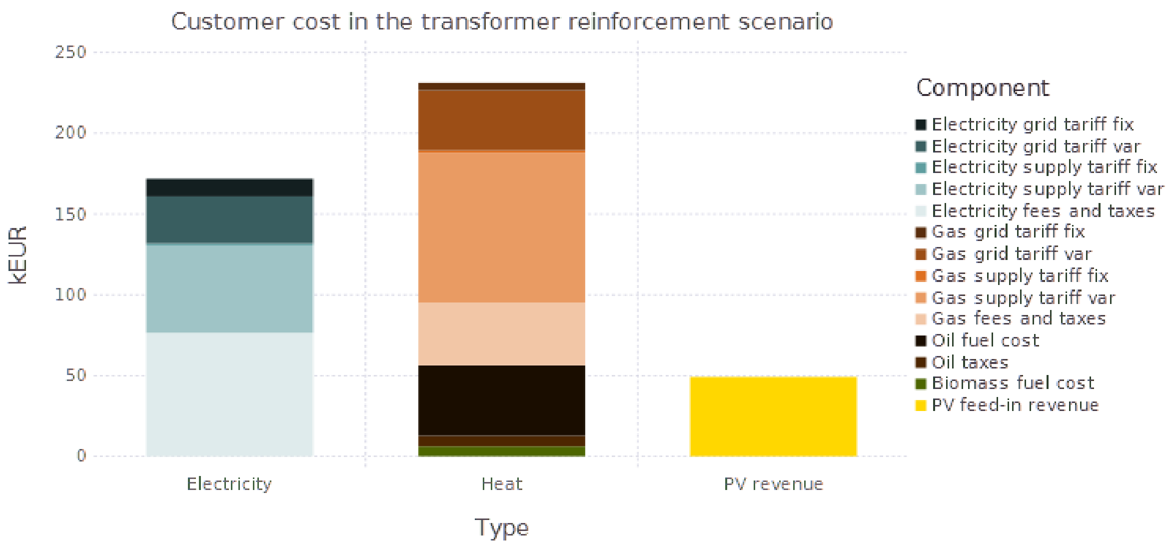

Figure 12: Aggregated annual cost for energy procurement and PV feed-in revenue of all customers in the transformer reinforcement scenario.

If a more powerful transformer was available, less energy from local PV generation would have to be curtailed and the customers could achieve more revenue from PV feed-in. Figure 12 shows the annual cost of all customers after a transformer reinforcement. The cost for electricity and heat is the same as in the baseline scenario, but the revenues from PV feed-in are increased by 7800 EUR. Thus, the final annual cost of all customers is decreased by 7800 EUR.

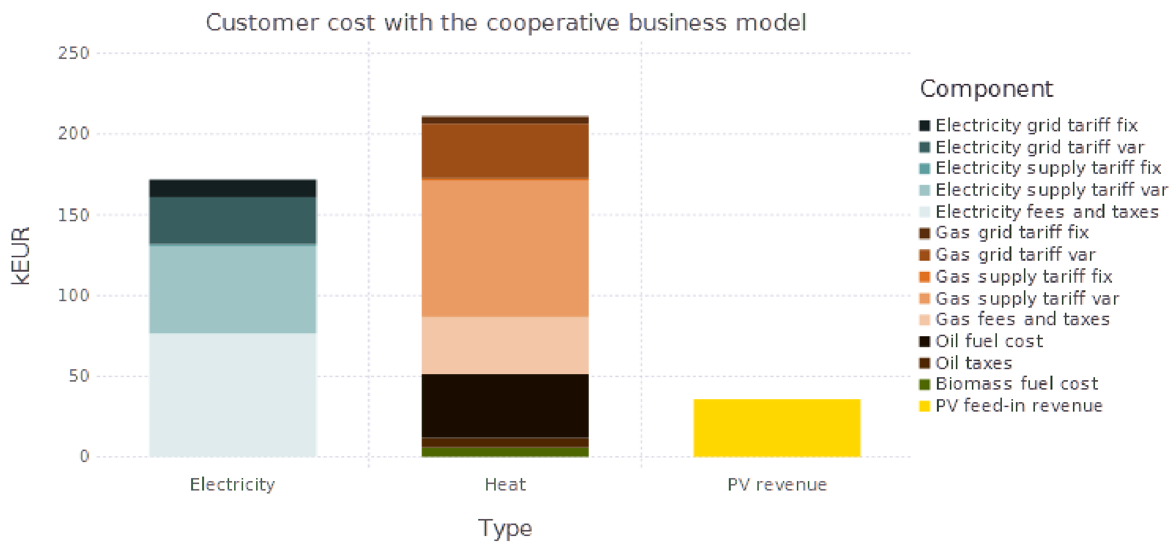

Figure 13: Aggregated annual cost for energy procurement and PV feed-in revenue of all customers with the new cooperative business model

The final aggregated costs of all customers with the novel cooperative business model are shown in Figure 13. It can be seen that, on the one hand, customers earn less revenue from PV feed-in compared to the baseline scenario, but, on the other hand, costs for heat, namely for domestic hot water heating, are significantly reduced. Altogether, annual cost is decreased by 14500 EUR.

Table 24: Cost savings and maximum investment cost for different scenarios

	Annual cost [EUR]	Cost savings compared to baseline [EUR]	Interest rate	Economic lifetime in years	Maximum investment cost [EUR]
Baseline	359983.11				
Transformer reinforcement	354134.63	7781.32	5%	30	119618.02
Cooperative business model	345463.29	14519.82	5%	10	112118.21

Note, that the investment cost for the new transformer or the cost for the distributed electric boilers, the ICT infrastructure and the controller are not included in Figure 12 and in Figure 13. It can be assumed that the costs for these investments, which are made by the DSO, are passed on to the customers via the electricity grid tariff. If an interest rate of 5% and an economic lifetime of 30 years for the transformer are assumed, this would yield maximum investment cost of 120000 EUR, in order not to exceed the total baseline cost. If an economic lifetime of 10 years is assumed for the electric boilers, the ICT infrastructure and the controller, the maximum investment cost for the novel hybrid business model is given by 112000 EUR or 824 EUR per household. The major cost parameters are shown in Table 24.

3.3.3 Acceptance and the Pareto criterion

In this section the cost redistribution effects among different customer types – ***PV*** (prosumers with PV systems) and ***passive*** (customers without PV systems) – and different stakeholders in general are investigated for a transformer reinforcement and the implementation of the novel cooperative business model.

3.3.3.1 Transformer reinforcement

Apart from technological network stability issues concerning e.g. the electricity grid voltage, which are investigated in Task T4.3.1 [1], only customers with PV systems can benefit from a transformer reinforcement in economic terms. With a more powerful transformer less electricity from PV systems is curtailed and ***PV*** customers can therefore generate more revenue from surplus feed-in. ***Passive*** customers, on the other hand, are not affected by this investment. The costs, however, are passed on to all customers via the electricity network charges.

In the following the maximum investment cost from Table 24 are assumed for the transformer investment. This way the aggregated total costs for all customers are the same as in the baseline scenario. Figure 14 shows that there are extra costs due to the additional grid tariff. However, the increased revenue from PV feed-in brings about the same final cost (illustrated by the yellow points).

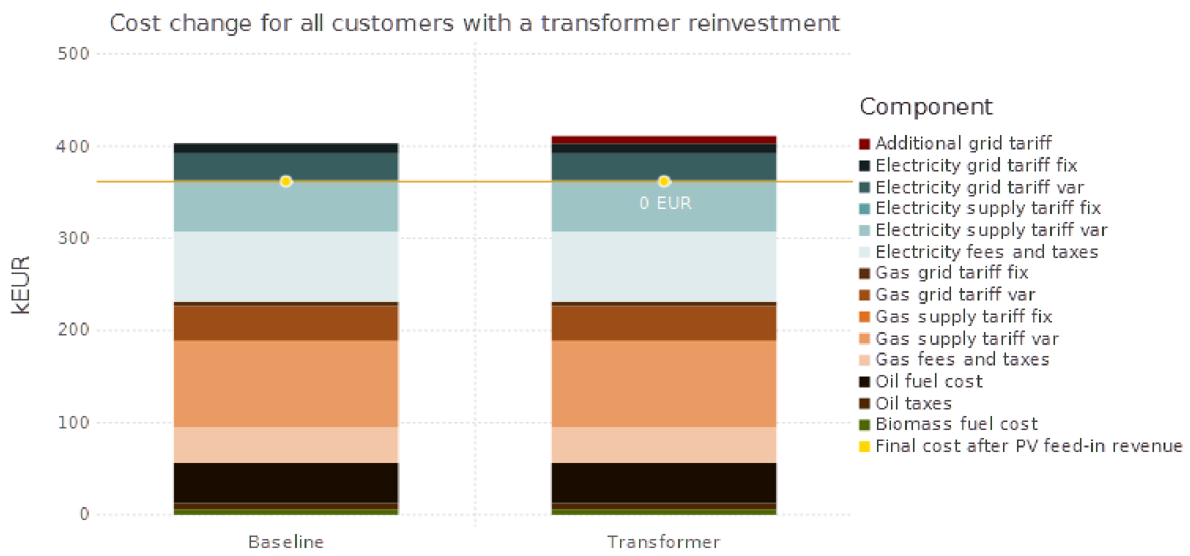

Figure 14: Cost change for all customers with a transformer reinvestment

The cost change for ***PV*** customers is illustrated in Figure 15. They receive all the benefit from the transformer reinforcement in the form of higher revenue from surplus feed-in, but only pay a part of the investment via the additional grid tariff. Thus ***PV*** customers can reduce their cost in this scenario by about 1600 to 2200 EUR depending on whether the additional grid tariff is passed on to the variable or to the fixed component. Conversely, the cost of the ***passive*** customers is increased by the same value in the transformer reinforcement scenario, which is shown in Figure 16.

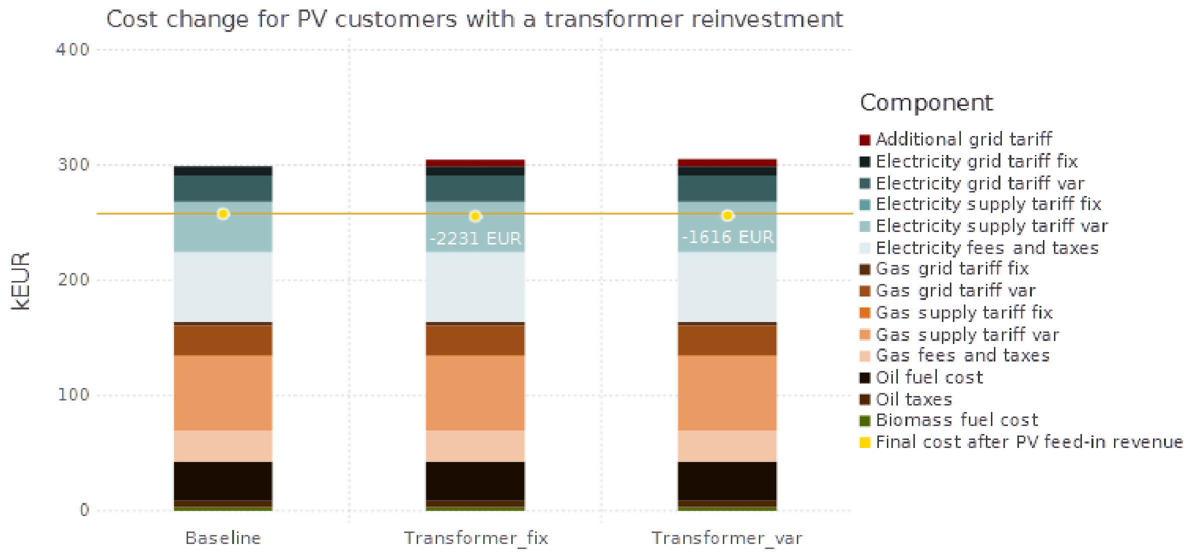

Figure 15: Cost change for PV customers with a transformer reinvestment

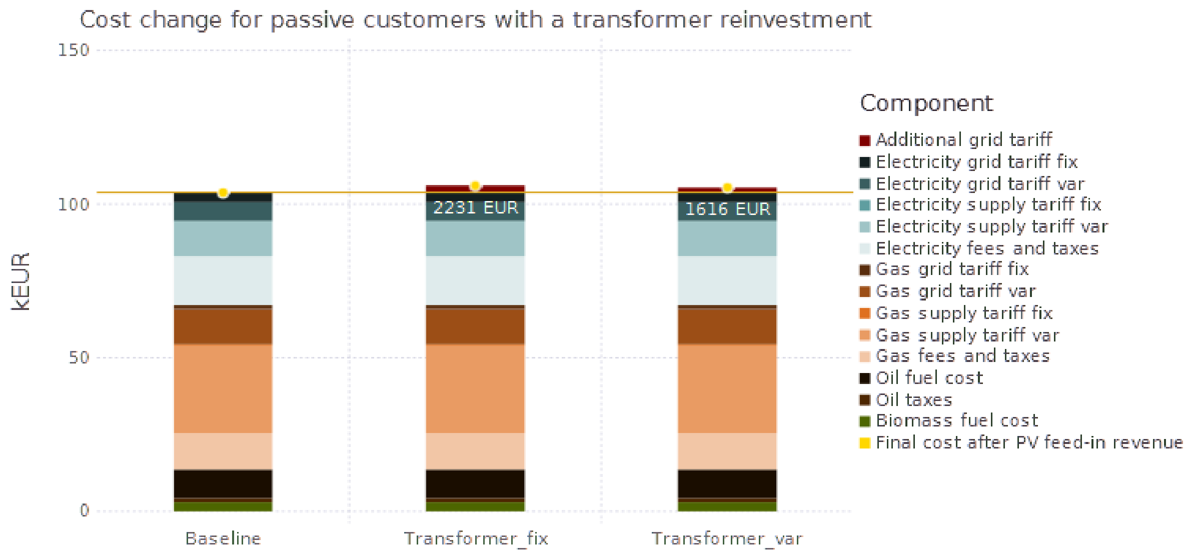

Figure 16: Cost change for passive customers with a transformer reinvestment

Note that the ***PV*** customers seem to benefit more if the additional costs are passed on to the fixed tariff component. This is quite surprising and cannot be deduced as a general rule, but rather is a result of the particular composition of the customers demand data in this use case: The ***PV*** customers in the considered data set have on average significantly higher electricity demand than the ***passive*** customers and, thus, the share of electricity purchased by ***PV*** customers is still higher than the share of ***PV*** customers. In general, rather the opposite can be assumed: If all customers have more or less the same electricity demand, ***PV*** customers purchase on average less electricity, because they also have self-generation. In that case the share of electricity purchased by ***PV*** customers would be lower than the share of ***PV*** customers. Consequently, in general, ***PV*** customers would prefer additional costs to be passed on to the variable tariff component and ***passive*** customers would prefer an increase of the fixed component. This observation is also true for the following results with the cooperative business model.

3.3.3.2 Cooperative Business model

The implementation of the novel hybrid cooperative business model does not only affect the revenue from PV surplus feed-in and an additional network tariff, but also influences the cost for heating, because a significant share of hot water demand is heated by PV surplus. It can be seen in Figure 17 that the costs for natural gas, heating oil and biomass are reduced. Just as in the transformer reinforcement scenario the maximum investment cost for the cooperative business model from Table 24 are considered here, and thus the aggregated final cost of all customers are the same as in the baseline scenario with the additional grid tariff. It is again assumed that the DSO makes the investment and passes on the costs to the customers either through the fix or through the variable tariff component. The investment cost for the cooperative business model include the cost for the installation of the distributed electric boilers at household level, the cost for the central software controlling the distributed heating rods and the costs for required ICT infrastructure. The maximum total investment cost amount to roughly 112000 EUR or 820 EUR per household.

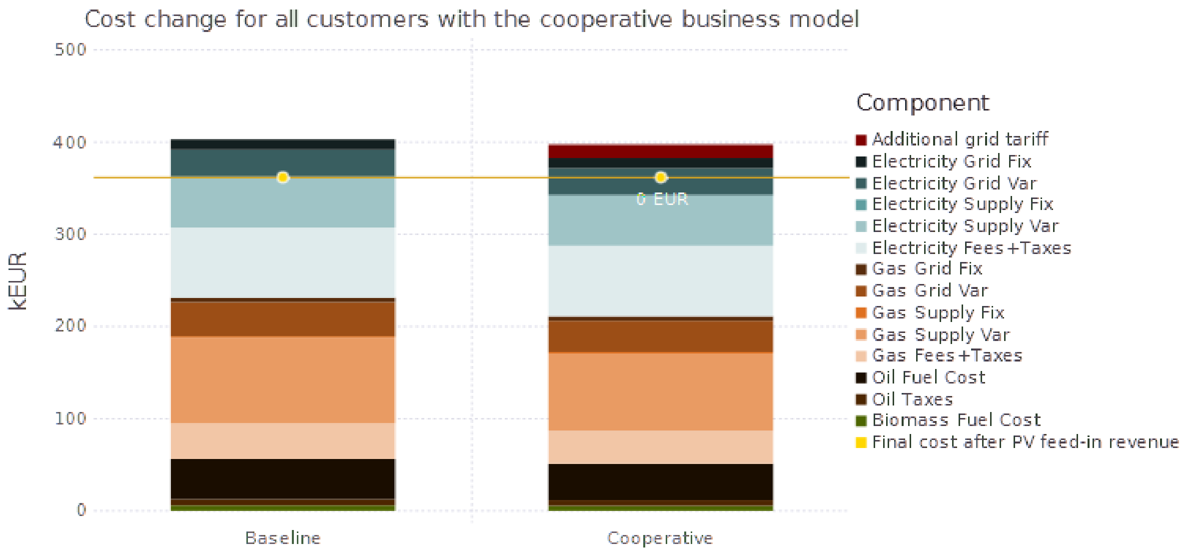

Figure 17: Cost change for all customers with the cooperative business model

The cost change for ***PV*** customers with the cooperative business model is illustrated in Figure 18. Their costs for heating are reduced and they have to pay an additional grid tariff. Furthermore their revenue from PV surplus feed-in is also reduced compared to the baseline scenario, because a part of the PV surplus is shared among other customers for domestic hot water heating. In total this results in higher final costs for ***PV*** customers with the new cooperative business model by 1400 to 2600 EUR depending on how the additional tariff is distributed between the fix and the variable component.

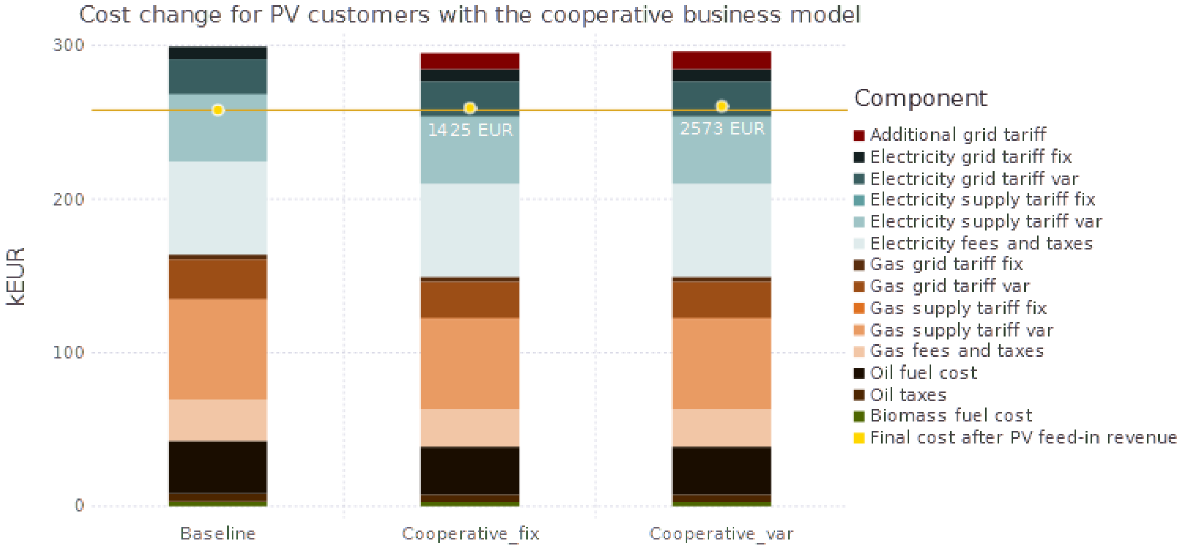

Figure 18: Cost change for PV customers with the cooperative business model

The reverse cost change can be seen in Figure 19 for passive customers. Thus, in contrast to the transformer reinforcement scenario passive customers benefit from the implementation of the cooperative business model, because they save fuel for hot water heating. In total 240 MWh of PV surplus are shared locally for domestic hot water heating. However, thereof only 88 MWh are bought by ***passive*** customers, the remaining energy is shared among ***PV*** customers. Thus, if the PV customers received 1.62 ct/kWh - or 2.92 ct/kWh respectively for an additional variable component – for shared PV surplus and all customers paid the respective amount for used PV surplus, both customer groups would have the same final cost as in the baseline scenario. Note, however, that this does not ensure that all individual customers have the same costs as in the baseline scenario.

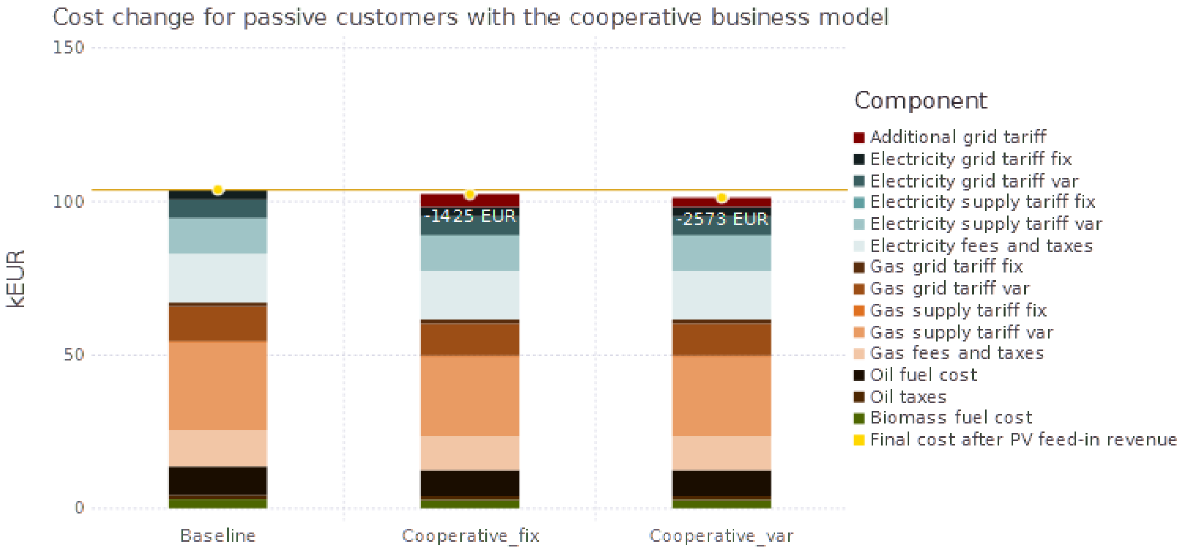

Figure 19: Cost change for passive customers with the cooperative business model

3.3.3.3 Varying the investment cost

Until now only the maximal investment costs have been considered. Of course the prospect of the business model or a transformer reinvestment strategy can look different with different investment cost.

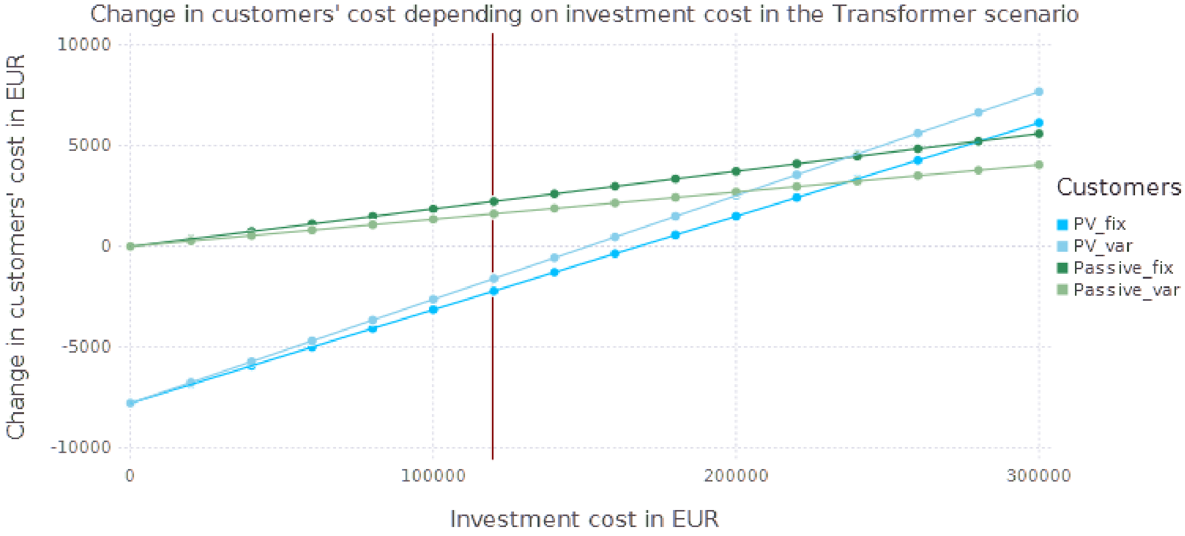

Figure 20: Change of customers' final cost depending on the transformer investment cost by customer group and increased tariff component

Figure 20 shows, how the customers' final cost would change with a transformer reinforcement for different transformer investment cost. The vertical red line indicates the maximal investment cost, not to exceed the total baseline cost of all customers. Hence, if the transformer was cheaper than this, the customers in total could benefit by the reinforcement. However, passive customers cannot benefit from this strategy without receiving any of the additional revenue from PV customers.

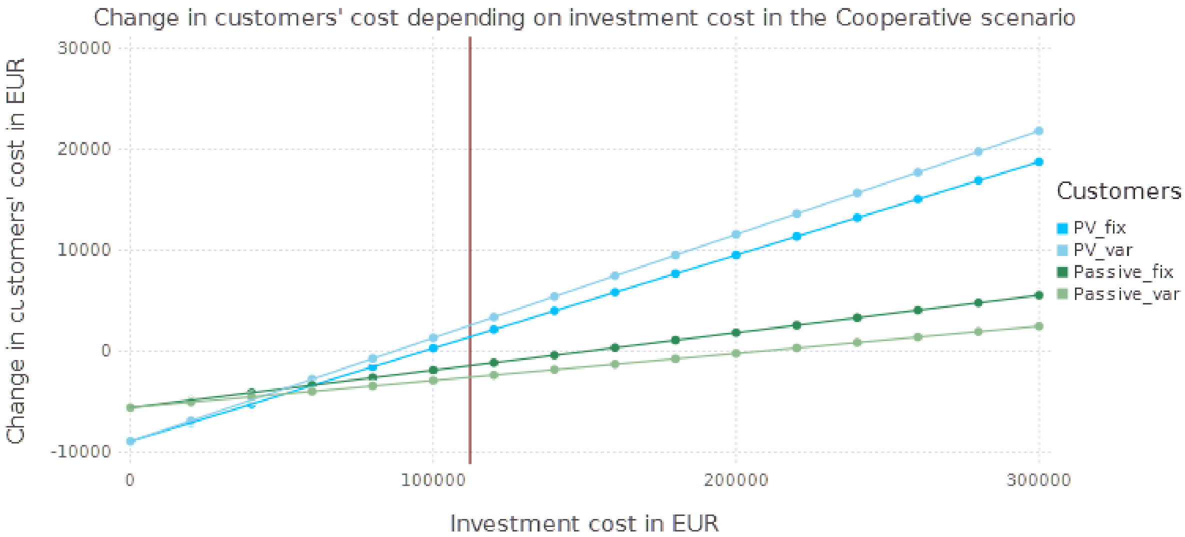

Figure 21: Change of customers' final cost depending on the cooperative business model investment cost by customer group and increased tariff component

Figure 21 shows the change of customers cost with the implementation of the cooperative business model depending on the investment cost for different customer groups. In contrast to the transformer reinforcement scenario all customers can benefit from this strategy up to the vertical red line indicating the maximal investment cost. This can be achieved by introducing a small tariff between 1.6 and 2.9 ct/kWh for shared PV surplus. For investment cost below 85000 EUR (or 95000 EUR, respectively) the Pareto criterion is satisfied even without introducing a new tariff.

3.4 Conclusions and recommendations

- The theoretical[2] maximal annual feed-in could be reduced with the implementation of the new business model. Depending on the electric boiler nominal capacity it can be decreased by 134 kW for 1 kW boilers and 176 kW for 2 kW boilers, respectively.
- The local usage of electricity produced by PV systems can be significantly increased with the cooperative business model. In the considered PV75 scenario this increase amounts to 275 MWh per year.
- The cooperative business model facilitates a reduction of natural gas, oil and biomass usage and, hence, a reduction of greenhouse gas emissions. The CO_2 emissions can be reduced by 70 tons per year.
- For PV customers a transformer would be more beneficial, because they can increase their revenue and passive customers pay part of the investment via the network tariff. Note, that this is only true, if PV customers are remunerated for feed-in of PV surplus.
- For passive customers the implementation of the cooperative business model would be more beneficial: While only PV customers lose part of their revenue from PV surplus, all customers save cost for hot water heating.
- The cooperative business model could fulfil the Pareto criterion among the customer groups with the implementation of a tariff for shared PV surplus electricity.
- In general, PV customers would prefer additional cost to be passed on via the variable tariff component and passive customers would prefer an increase of the fix component.

[2] This feed-in is not actually achieved, because it would exceed the nominal capacity of the transformer and PV surplus is curtailed.

3.5 Further investigations

3.5.1 Using additional electric boilers for space heating

An idea to further increase the impact of the hybrid cooperative business model on the residual load, on cost savings and on fossil fuel reduction is to use PV surplus for space heating as well. Thus an additional variation of the first Ulm scenario has been investigated, where both, electric boilers for space heating and electric boilers for domestic hot water heating, are considered in each customers household. Figure 22 shows a conceptual overview of this scenario. ***PV*** customers can use their self-generated energy to satisfy their electricity demand and to operate the electric boilers for hot water heating and space heating, respectively. If additional surplus remains, it can be either shared locally, via the aggregator or sold otherwise. The aggregator in Figure 22 represents the controller operated by the DSO. If supply and demand of PV surplus for heating are available at the same time in the considered LV network branch, the controller activates the respective electric boiler.

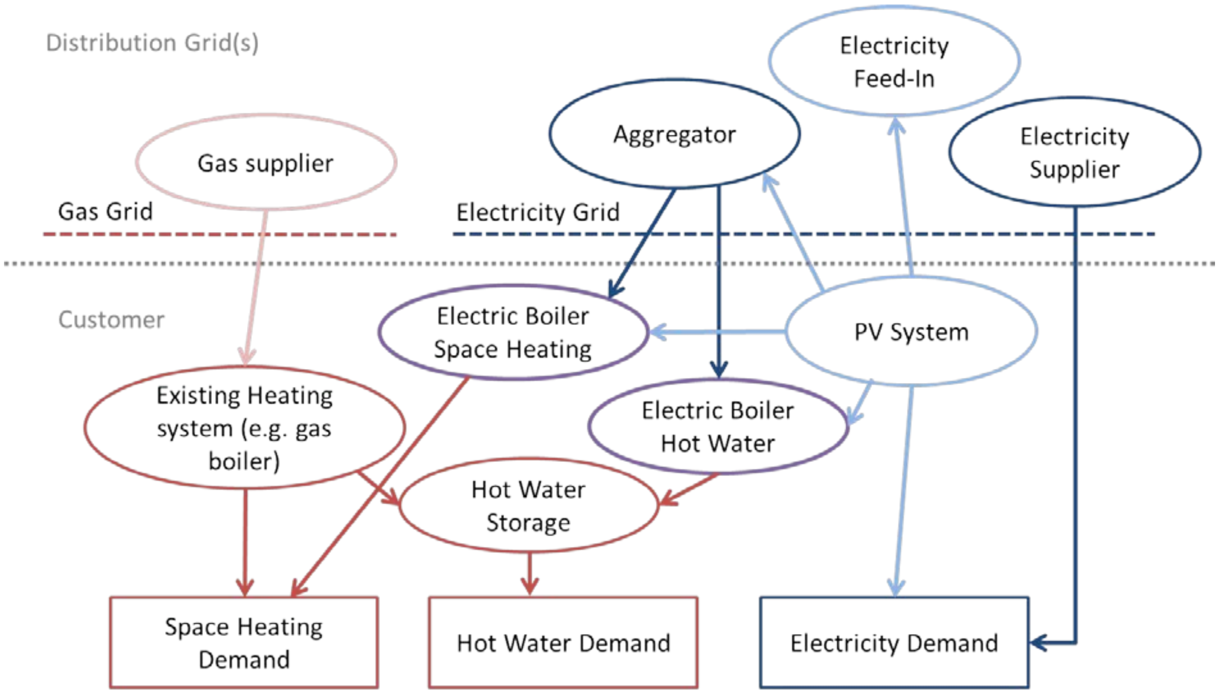

Figure 22: Conceptual overview of a customer's energy supply with hybrid cooperative business model and additional electric boilers for space heating.

The business model is supposed to be the same as in the main Ulm use case. The DSO invests in the electric boilers for both, hot water heating and space heating, the controller and the required ICT infrastructure. These investment cost are passed on to the local customers via the network charges. All customers save cost for heating by reducing the fuel usage of their alternative heating system. The ***PV*** customers, however, also lose part of their revenue from electricity feed-in by sharing PV surplus locally. Depending on the investment cost for the implementation of the new business model, win-win situations among both customer groups, ***PV*** and ***passive***, can be achieved by introducing a fee or tariff for the shared PV surplus remunerating the ***PV*** customers.

The annual load duration curves on the MV/LV transformer with different business models are illustrated in Figure 23. The theoretical maximal annual feed-in can be reduced by 240 kW with the space heating business model – 60 kW more than with the initial cooperative business model.

Although the additional electric boilers for space heating cannot significantly reduce the maximal feed-in, they can substantially increase the local usage of PV surplus.

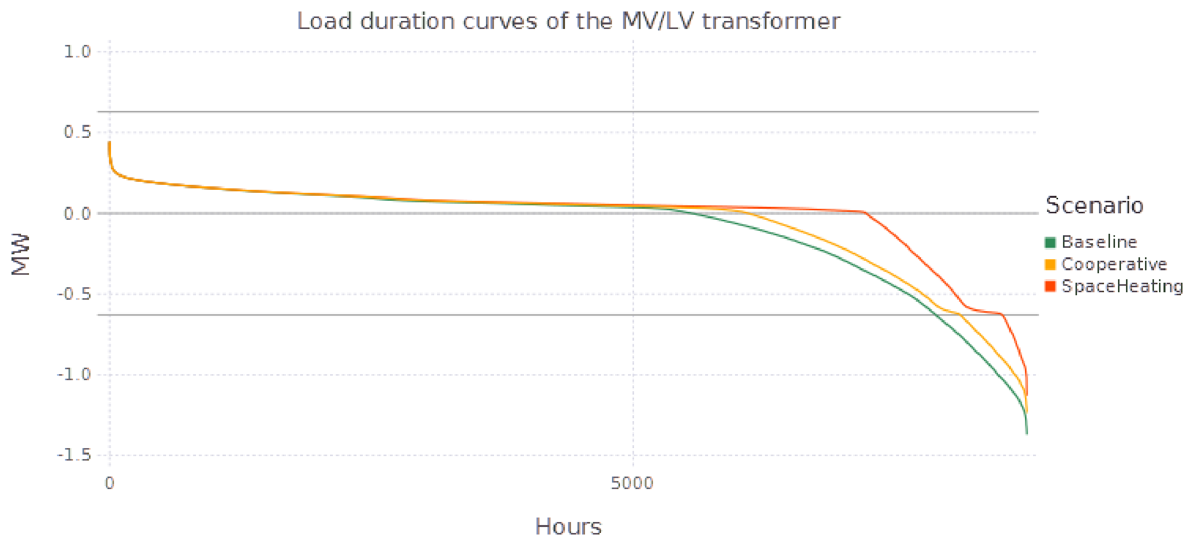

Figure 23: Annual load duration curves at the transformer in the PV75 scenario.

Figure 24 shows the usage of the local PV generation in four different business models. The first three bars on the left are the same as in Figure 9. The bar on the right corresponds to the cooperative business model with additional electric boilers for space heating. It can be seen that the additional electric boilers help to increase local usage of PV surplus. Compared to the Baseline, the annual medium voltage network feed-in is reduced by 500 MWh and the curtailment of PV surplus is reduced by 200 MWh. Thus the local usage of PV production is increased by 700 MWh or 40 percent of total production.

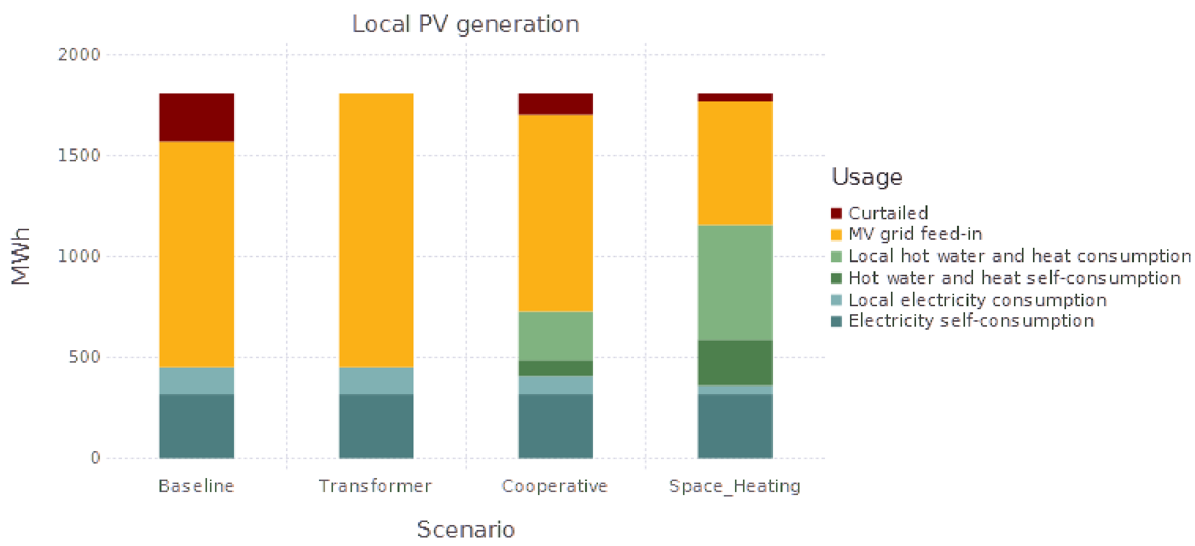

Figure 24: Annual usage of local PV generation in different business models with the PV75 scenario.

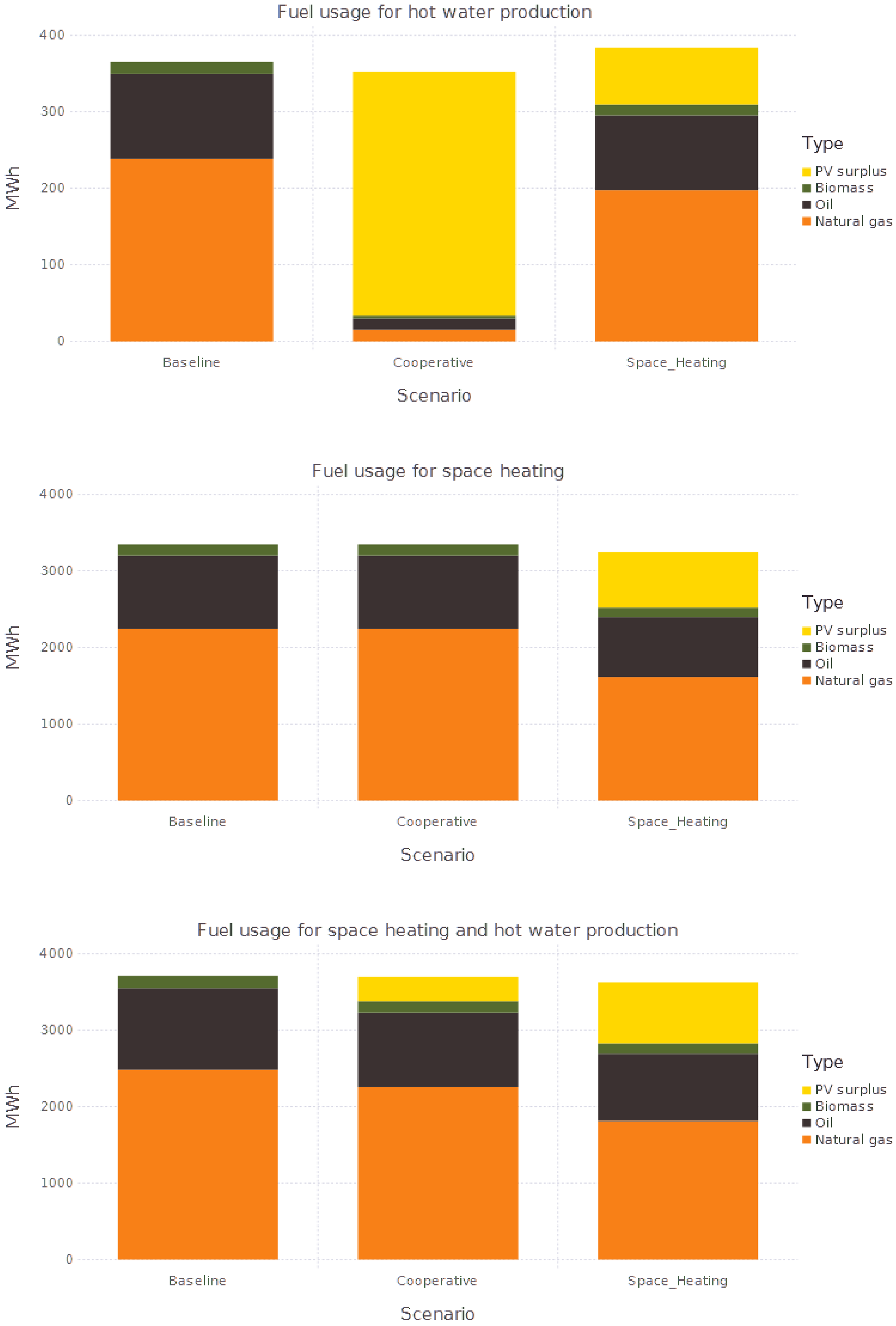

Figure 25: Fuel usage for hot water production, space heating and both with different business models in the PV75 scenario

The fuel usage of the primary heating systems is further reduced with the installation of additional electric boilers for space heating. Figure 25 shows the fuel used for hot water production, the fuel used for space heating and the fuel used for both, hot water production and space heating, with different business models. In total, 670 MWh of natural gas, 190 MWh of heating oil and 22 MWh of biomass can be saved per year with the cooperative space heating business model compared to the baseline. Using the fuel emission factors of [12] this corresponds to 185 tons of CO_2, 4.4 tons of CH_4 and 0.7 tons of N_2O per year.

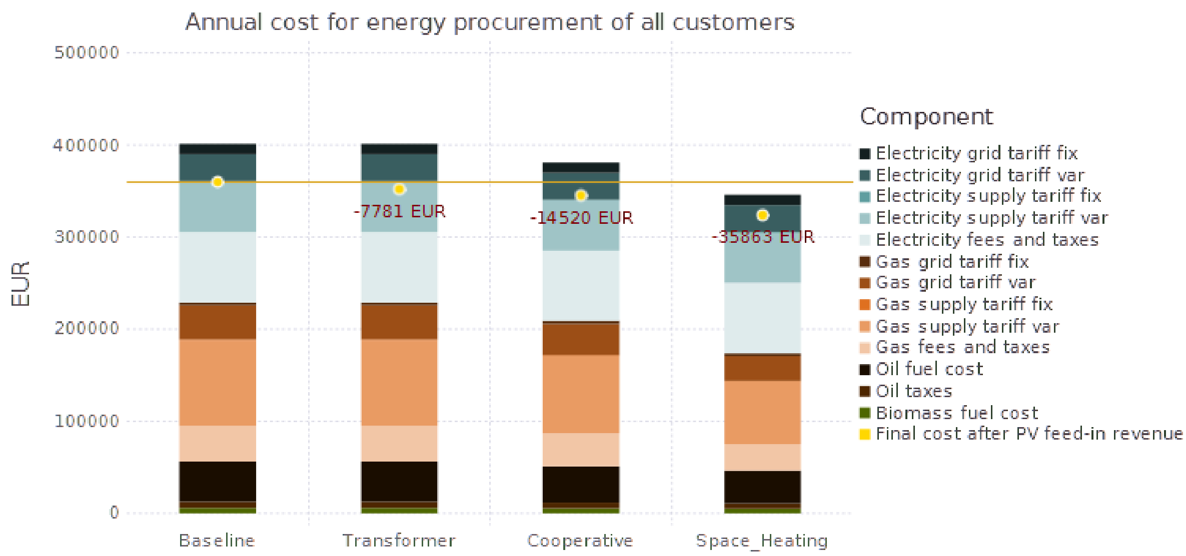

Figure 26: Annual cost for energy procurement of all customers with different business models.

The annual cost for energy procurement of all customers is illustrated in Figure 26 for different business models. Note, however, that the additional investment costs for a new transformer or additional electric boilers are not considered here. From Table 24 in Section 3.3.2 the maximal investment cost for the transformer (120000 EUR) and the cooperative business model (112000 EUR) are already known. If again an economic lifetime of 10 years and an interest rate of 5% are assumed, the investment costs in the space heating scenario can maximally amount to about 277000 EUR or 2000 EUR per household. Note, however, that this also has to include all investments of the cooperative hot water heating scenario, i.e. for the electric boilers for hot water production, for the ICT infrastructure and the controller, as well as for the electric boilers for space heating.

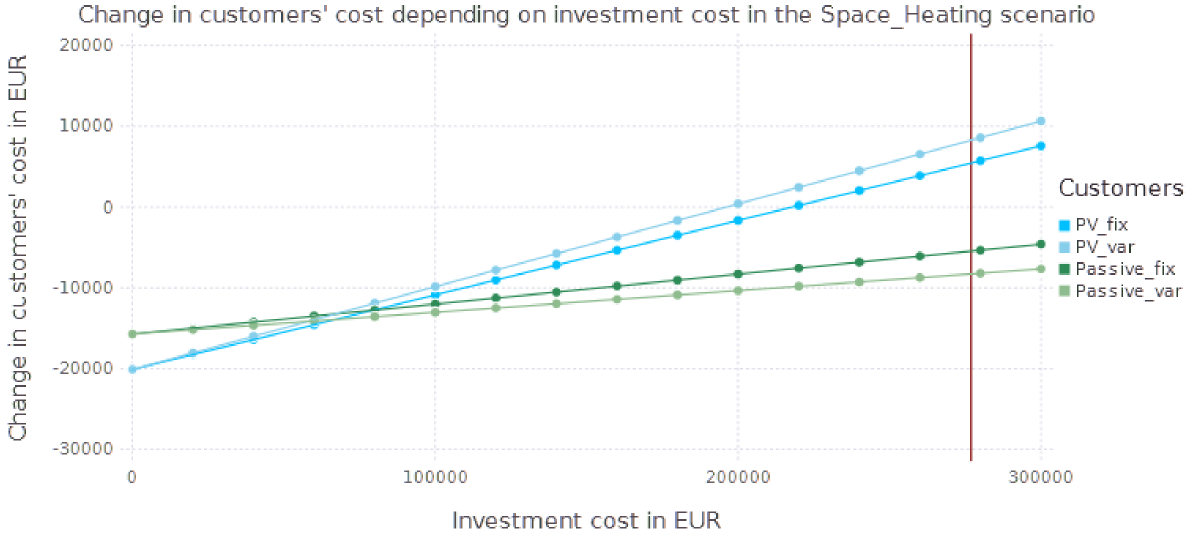

Figure 27: Change of customers' final cost depending on the space heating scenario investment cost by customer group and increased tariff component

4 Future scenario in Skellefteå

The future scenario in Skellefteå mainly revolves around the idea of using a more efficient coupling technology and waste heat from an energy-intensive industry for heat production. In this advanced case study the operation and cost of a very flexible coupling point consisting of a combined heat and power plant (CHP), a thermal storage, a heat pump and a battery are investigated. The utilization of waste heat shall help reduce the usage of other fuels used for heating, like biomass and electricity.

4.1 Scenario and business model description

In this future scenario for Skellefteå it is assumed that no oil boilers are available for heat production during peak demand hours. However, there is a 24 MW electric boiler located close to the demand center and the existing heat production and storage technologies at the Hedensbyn site are used for base and medium load: There is the 98 MW biomass-fired CHP, the 25 MW biomass boiler and the existing 15000 m³ hot water storage tank. Furthermore it is assumed that that a very energy intensive industry, like a data center, is moving to Skellefteå, which would be desirable from a socio-economic perspective of the municipality of Skellefteå. Furthermore, such an industry produces a significant amount of waste heat, which could be a further cheap heating source for Skellefteå Kraft, in combination with a heat pump. This scenario tries to identify a business case that Skellefteå Kraft could offer to an industry in order to incentivize them to move to Skellefteå and so that both players can benefit.

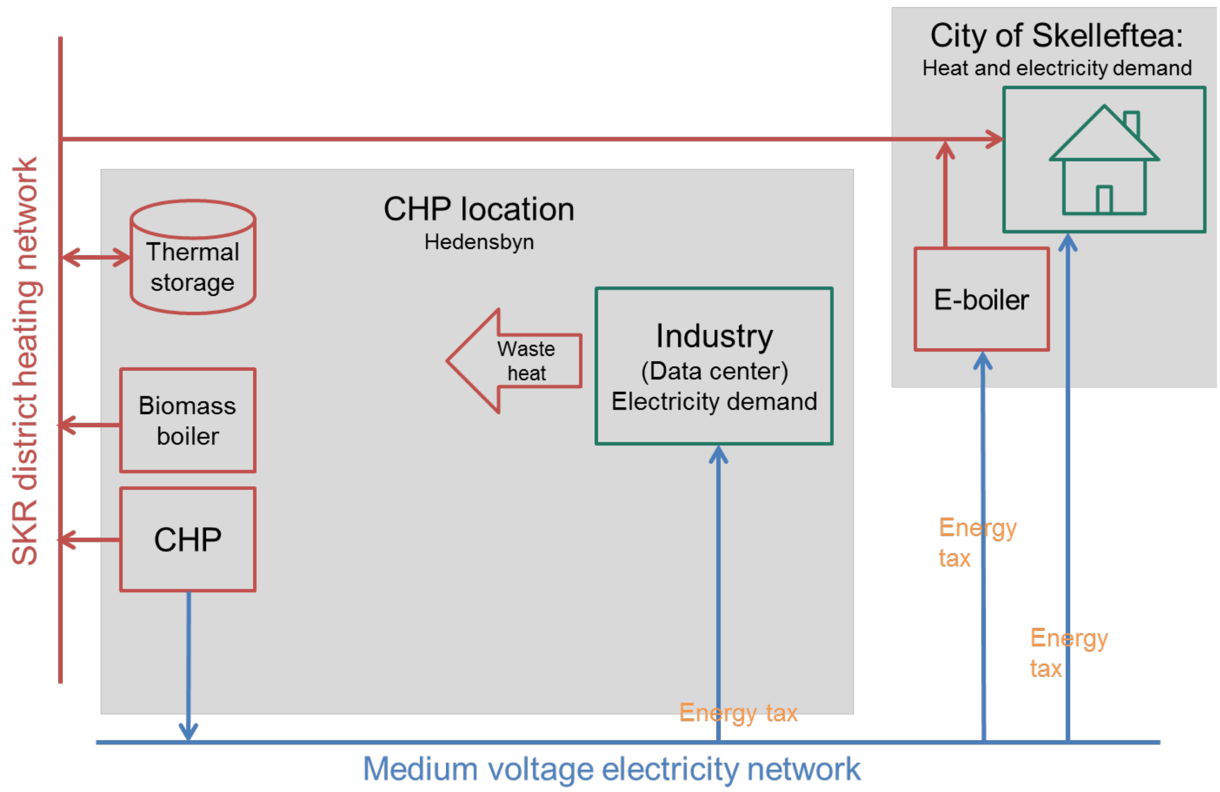

Figure 28: Conceptual overview of the baseline for the future scenario in Skellefteå

In order to show potential benefits of a cooperative business model a baseline has to be investigated first, where both players are acting independently. This is illustrated in Figure 28. SKR is producing heat with the CHP, the biomass boiler and the electric boiler, supported by the thermal storage, to satisfy the heat demand. Furthermore, electricity produced by the CHP is either used for electric boiler operation or sold on the wholesale spot market. The industry is buying electricity, either from a third party or on the wholesale spot market and the waste heat is lost. The energy tax on electricity usage has already been identified as a key factor for the profitability of power-to-heat systems in the today's scenario in Skellefteå. In the baseline scenario the energy tax would have to be paid for the electricity used by the electric boiler and also for the electricity used by the data center.

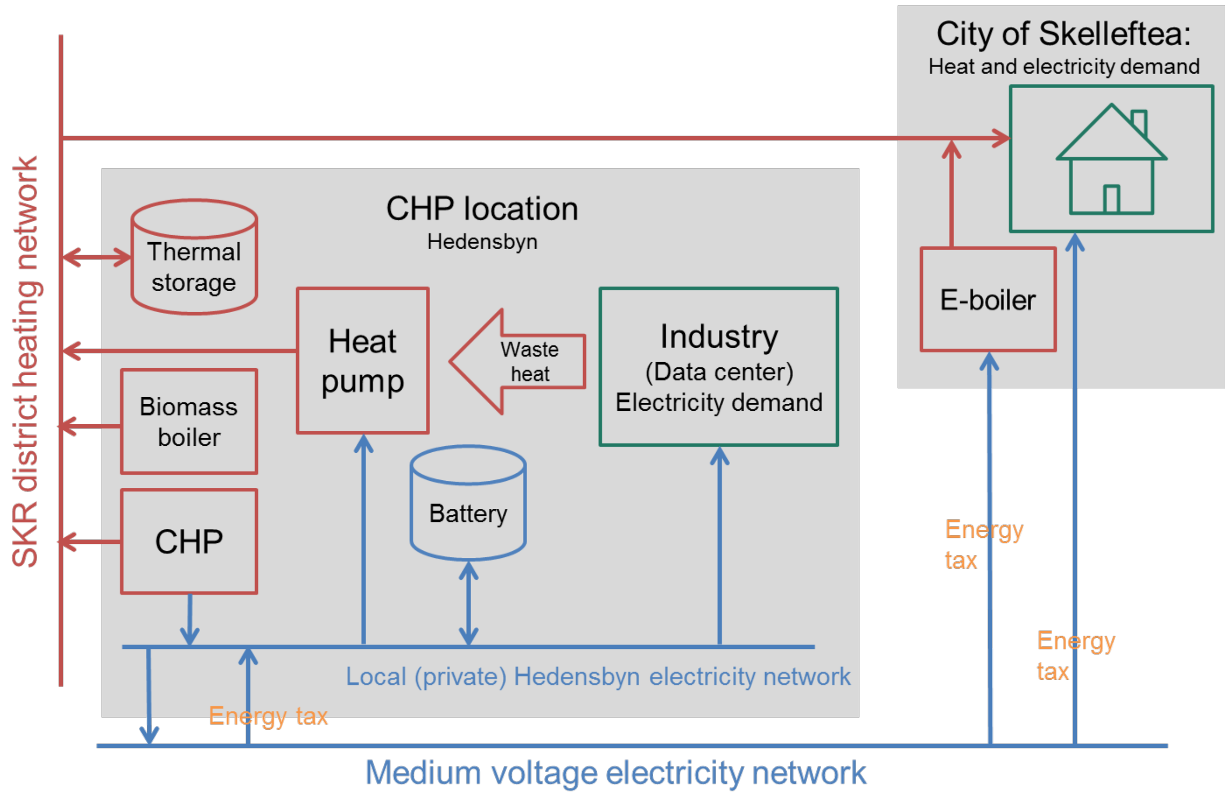

Figure 29: Conceptual overview of the advanced future scenario in Skellefteå

The advanced hybrid cooperative business model investigated in the future scenario in Skellefteå is illustrated in Figure 29. Here, SKR is investing in a heat pump to use the waste heat of the industry and a battery, making the entire technology portfolio located in Hedensbyn a very flexible hybrid coupling point. Furthermore, it is assumed that SKR is providing and selling the electricity to the industry and that the total technology park in Hedensbyn is appearing as one connection point to the public medium voltage electricity grid. Naturally this also means that the required electricity network infrastructure behind this connection point would have to be provided by Skellefteå Kraft.

The industry could benefit from lower electricity cost from this approach, because electricity produced by the CHP could be used directly, which may be cheaper than the current spot market price and it is free from the energy tax, because the public network only "sees" the residual demand at the common connection point. Skellefteå Kraft, on the other hand, could benefit from cheap heat production using the heat pump and the waste heat from the industry. However, it has to be quantified, whether these benefits justify the additional investments into the heat pump and the battery.

Currently there is a proposition from the Swedish government to introduce a tax reduction for data centers in January 2017 from around 19.7 EUR/MWh to 0.51 EUR/MWh. This would of course mean that the considered cooperative business model would generate less benefits for both players, because less cost is reduced by energy tax saving. Thus, both scenarios for the energy tax for the industry have been considered in the investigation of this case study.

4.2 Economic Modelling

4.2.1 Mathematical model

The mathematical model used for the investigations of the future scenario for Skellefteå is an extended version of the model used in the today's scenario. Accordingly it is a linear optimization model based on the methods presented in Deliverable D2.2 [5]. The CHP, the biomass boiler, the electric boiler and the thermal storage are implemented in the same way as in the today's scenario. The heat pump is assumed to have a changing coefficient of performance depending on the time of the year from 2.5 in the winter to 3.5 in the summer. The nominal capacity of the heat pump varies in different scenarios depending on the size of the industry, which defines the amount of available waste heat.

4.2.2 Model Scaling

The data for the heat demand and the electricity prices are the same as in the today's scenario in Skellefteå. However, only one year is simulated in the future scenario instead of 20 years in the today's scenario. Thus three significant years have been chosen from the 20 years of heat demand data:

- Mild winter: low annual demand and low maximal demand
- Typical winter: average annual demand and average maximal demand
- Cold winter: high annual demand and high maximal demand

The investment cost data for batteries and heat pumps is based on the information provided in [11] and listed in Table 25: Investment cost for new technologies

Table 25: Investment cost for new technologies

	Investment cost	Economic lifetime
Heat pump	EUR/MW 700.000,-	10 years
Battery	EUR/MW 1.000.000,-	10 years

4.2.3 Sensitivity analyses

The variations for different parameters defining the scenarios are listed in Table 26. This results in 486 different model runs for the baseline and the advanced scenario, respectively.

Table 26: Parameter variations for the future scenario in Skellefteå

Winter type	Mild	Typical	Cold
Heat demand increase	5%	10%	20%
Electricity wholesale market price change	-20%	0%	20%
Industry electricity demand	10 MW	20 MW	30 MW
Battery size	1 MW	5 MW	10 MW
Industry energy tax		19.5 EUR/MWh	0.51 EUR/MWh

4.3 Results

The results presented here are the results of the economic models, which mainly show effects on the cost of different market participants and changes in fuel usage. Detailed technical results are presented in [4] and [2].

To exemplarily illustrate the economic model functionality and results, Figure 30 shows the heat production of the technology park of Skellefteå Kraft for one year in the future baseline scenario. The input parameters in this figure are a heat demand increase of 10%, a typical winter and unchanged electricity prices. It can be seen that the base load is provided by the biomass CHP. If the CHP heat output is not sufficient to satisfy the demand, the biomass boiler is operated and finally for peak demand the electric boiler is activated and supported by the thermal storage.

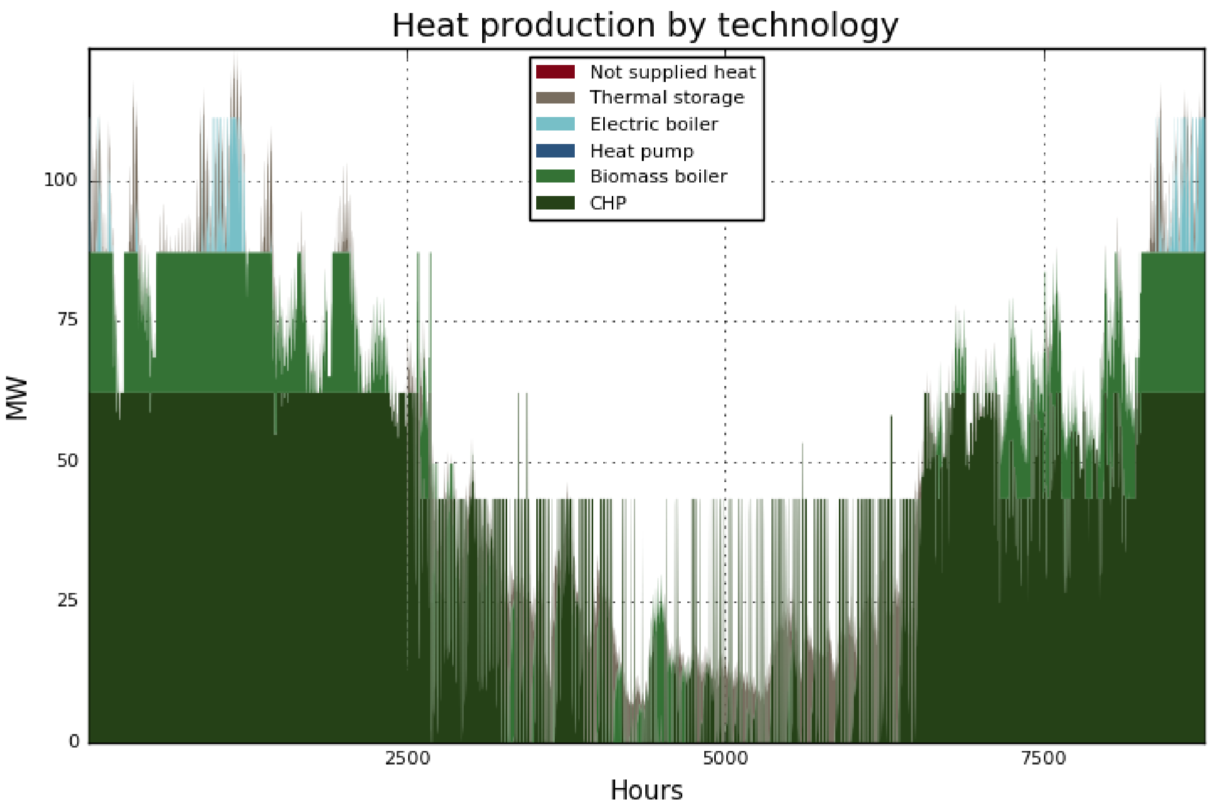

Figure 30: Annual hourly heat production by technology in the future baseline scenario with a heat demand increase of 10%, a typical winter and unchanged electricity prices.

Figure 31 and Figure 32 show how this annual heat production would change if the future advanced scenario would be implemented with the same demand and price parameters. Both assume a new industry size of 20 MW, a battery size of 5 MWh and a high industry energy tax. In Figure 31, however, it is assumed that the industry and the newly installed technologies are located at the CHP site, while in Figure 32 they are assumed to be somewhere else. In both of these configurations the heat pump replaces the biomass boiler as the second option for heat production after the CHP plant. The electric boiler is not used anymore in any of these two configurations. A significant difference between them is the operation in summer: If the industry, the heat pump and the battery are located at the CHP location (Figure 31) the CHP plant is operated during the summer months in order to provide cheaper electricity for the industry. If the new technologies are located somewhere else (Figure 32) the heat demand during the summer months is satisfied by the heat pump.

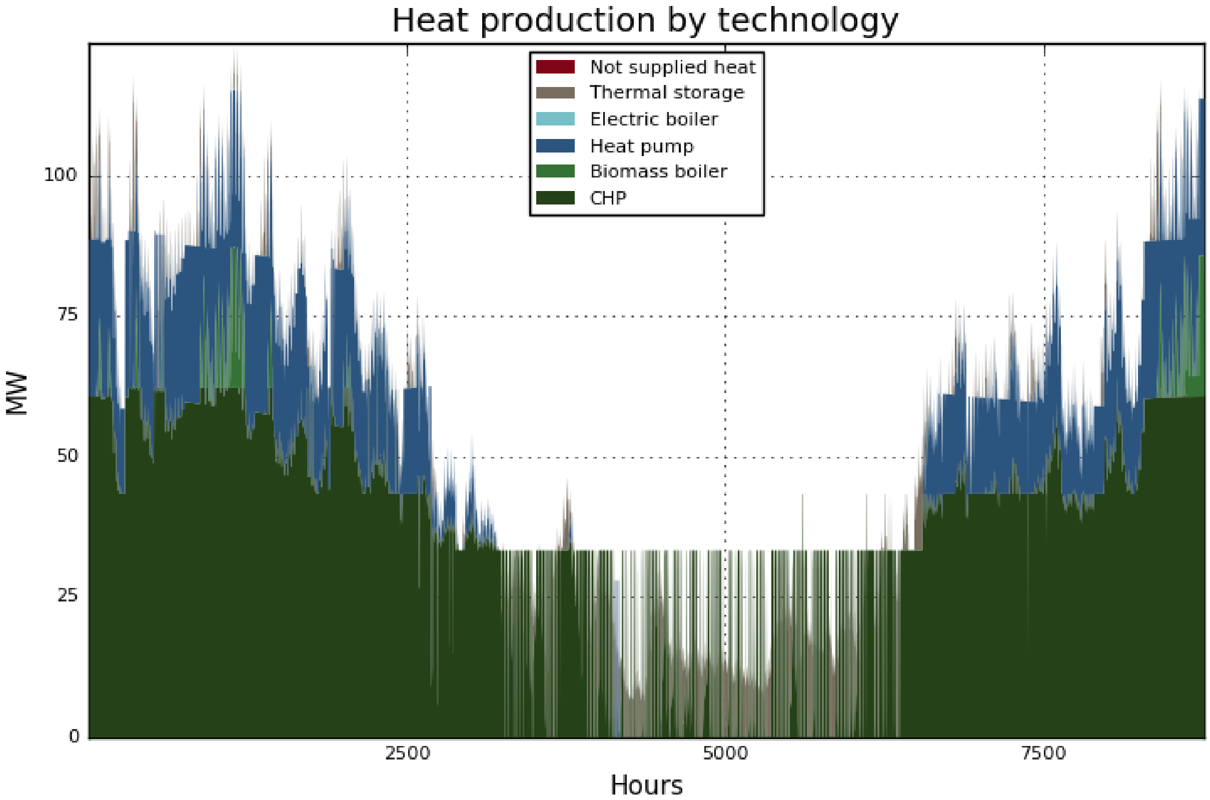

Figure 31: Annual hourly heat production by technology in the future scenario with a heat demand increase of 10%, a typical winter, unchanged electricity prices, the new technologies located at the CHP site, an industry size of 20 MW, a battery size of 5 MWh and a high industry energy tax.

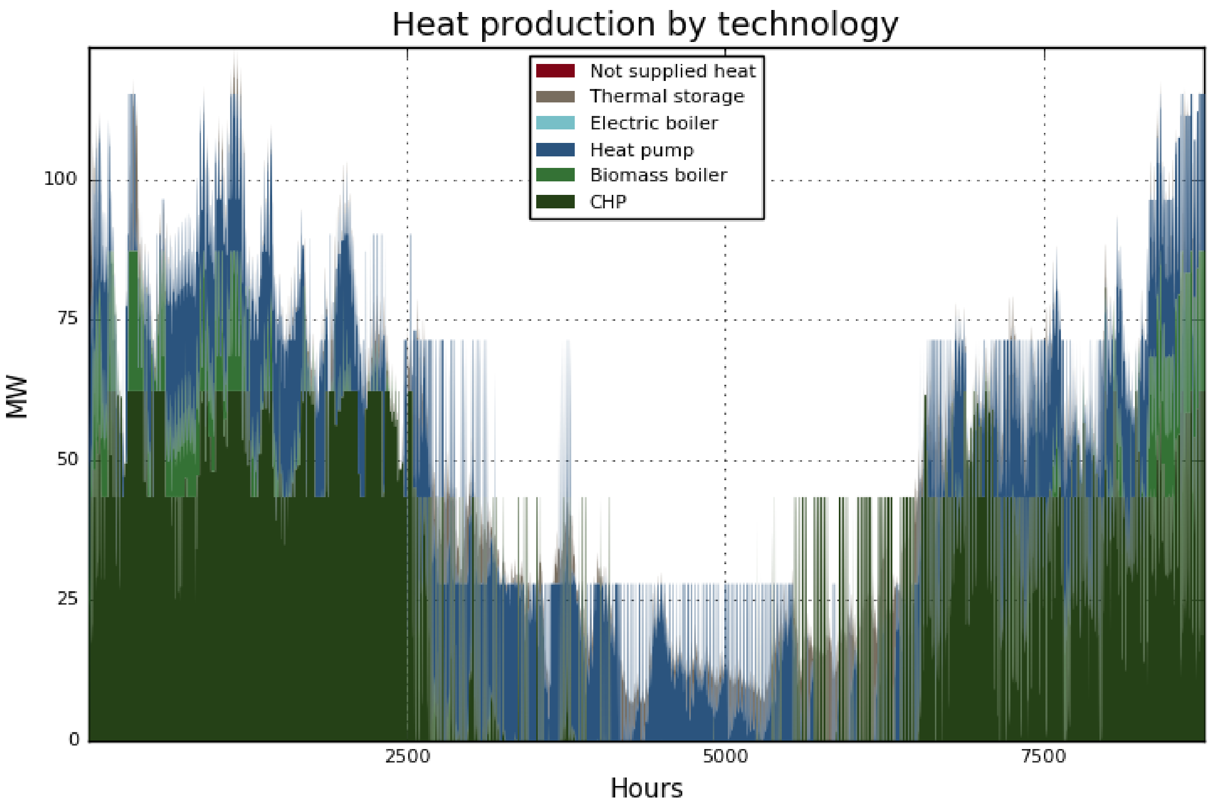

Figure 32: Annual hourly heat production by technology in the future scenario with a heat demand increase of 10%, a typical winter, unchanged electricity prices, the new technologies located at another site, an industry size of 20 MW, a battery size of 5 MWh and a high industry energy tax.

A lot of different scenario configurations have been simulated for the future scenario in Skellefteå and not all of the results can be shown and analyzed in detail. Thus, in the following only the results of the scenario with the default parameter values, shown in Table 27, are illustrated and investigated in detail.

Table 27: Default parameter values for the detailed result analysis.

Parameter	Default value
Winter type	Cold
Heat demand increase	20%
Electricity wholesale market price change	20%
Industry electricity demand	30 MW
Battery size	10 MW

4.3.1 Fuel savings

With the usage of a heat pump and waste heat of an energy-intensive industry biomass consumption can be reduced. Figure 33 shows the annual heat production by technology in different scenarios for a high and a low industry energy tax, respectively. It can be seen that in the high tax scenario the locating the industry and the heat pump at the CHP location leads to higher biomass usage than at another location, while in the low tax scenario it is the other way around. This is due to the fact that at the CHP location more CHP electricity output means that more of the industry energy tax can be avoided, which generates more benefits in the high tax scenario. Thus, more heat is produced by the CHP in this scenario too. In contrast, in the low tax scenario using the waste heat and operating the heat pump with the electricity from the CHP is more beneficial due to the high coefficient of performance of a heat pump and the relatively low savings by tax avoidance.

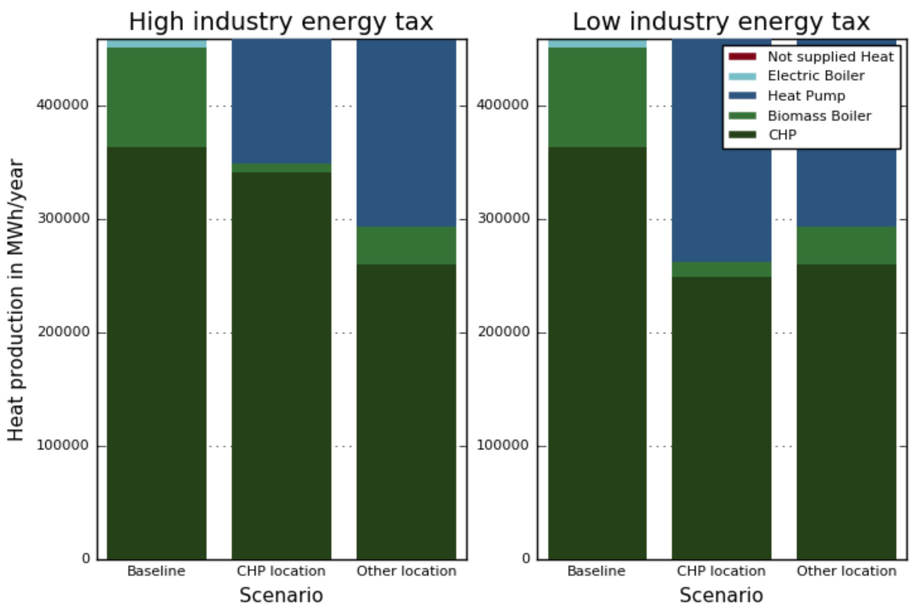

Figure 33: Annual heat production by technology for different energy tax and scenario configurations

The primary goal of the future use case in Skellefteå was not related to reduction of greenhouse gas emissions and biomass fuels are considered to be CO_2-neutral. Since a large share of the heat production in the future scenario in Skellefteå is provided by biomass-fired technologies, introducing additional power-to-heat devices and increasing the usage of electricity could be expected to increase the carbon footprint depending on the electricity emission factor. However, when incorporating the electricity consumption of the industry as well and considering the electricity produced by the biomass-fired CHP carbon-neutral the situation looks different. Figure 34 shows the annual fuel usage for heat production for satisfying the electricity demand of the industry. Here it can be seen that both, the total amount of electricity bought from the wholesale market and the consumption of biomass are reduced significantly in the advanced cooperative hybrid scenarios compared to the status quo.

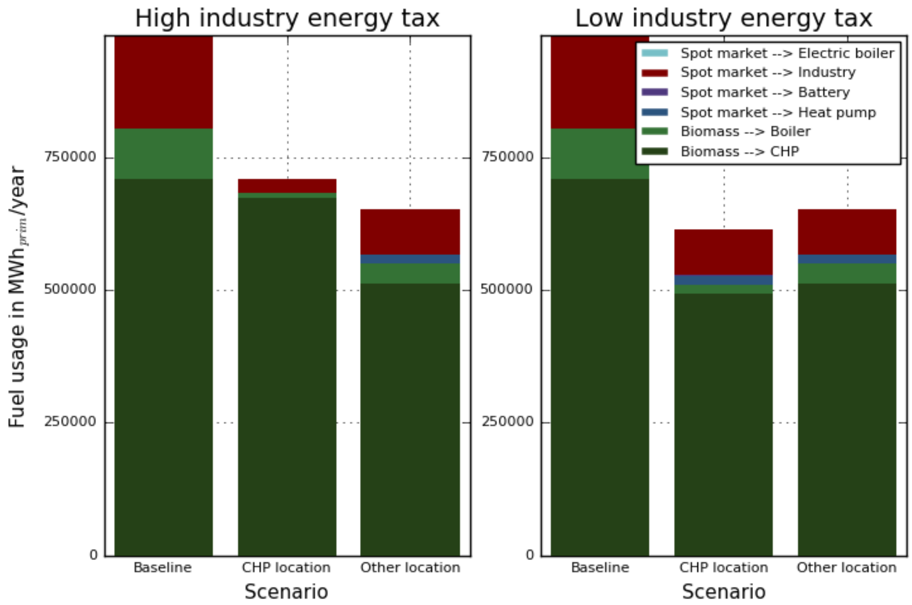

Figure 34: Annual fuel usage for heat production and industry electricity demand for different energy tax and scenario configurations.

4.3.2 Cost reduction

For the cost evaluation of the future advanced hybrid scenarios, both the annual heat production cost of Skellefteå Kraft and the annual electricity procurement cost of the industry have to be considered. The heat production cost of SKR in the future baseline scenario consists of the operational cost, i.e. fuel and maintenance cost, of the CHP plant, the biomass boiler and the electric boiler. Furthermore, the revenue from selling electricity on the wholesale market has to be considered. In advanced scenario this cost is complemented by the operational and investment cost of the heat pump and the battery. Besides, in the cooperative scenario SKR is selling electricity to the industry. In a first step this energy is supposed to be sold at the electricity wholesale market price.

The electricity cost of the industry is calculated with the electricity wholesale market price and the fees, taxes and network charges. Depending on the scenario, the energy cost is either paid to a third party on the electricity wholesale market (Baseline) or to Skellefteå Kraft (Advanced). Depending on the location of the industry in the future scenario, the industry can (CHP) or cannot (Other) avoid taxes and network charges for the electricity used from CHP production.

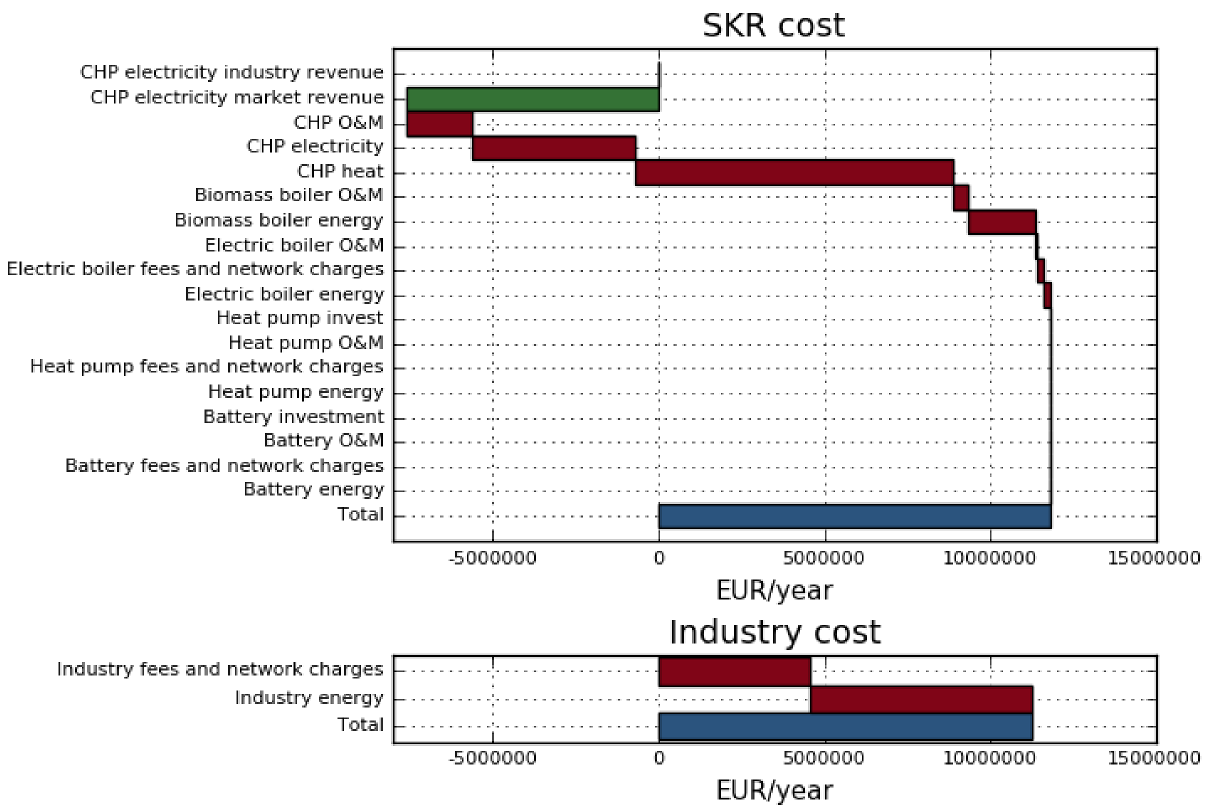

Figure 35: Annual cost components of Skellefteå Kraft and the industry in the baseline scenario.

The individual cost and revenue components of SKR and the industry in the baseline scenario are illustrated in Figure 35. All of the electricity produced by the CHP plant is sold on the electricity wholesale market. The highest annual cost share is associated with the CHP plant, because it is also producing most of the heat needed for the annual demand. A significantly lower share is related to the biomass boiler and the electric boiler has the least operational cost because it is only operated during peak hours. Note that for the technologies already existing in the baseline scenario investment costs are disregarded.

Figure 36 shows the annual cost components of SKR and the industry in the future advanced scenario with the novel technologies located at a different location than the CHP site in Hedensbyn. It can be seen that less electricity from CHP production is sold to the market compared to the baseline in order to provide energy for the industry. Furthermore, the annual costs for the CHP are reduced, because more heat is provided by the heat pump. However, the heat pump and battery investment costs together with the reduced electricity revenue result in significantly higher annual cost than in the baseline scenario. The industry, on the other hand, is confronted with the same cost as in the baseline scenario, because it is assumed to pay the current wholesale market price, either to SKR or on the market, and it cannot avoid energy taxes and network charges, when located at a different location than the CHP. Thus, this scenario would result in higher total costs for SKR and the industry.

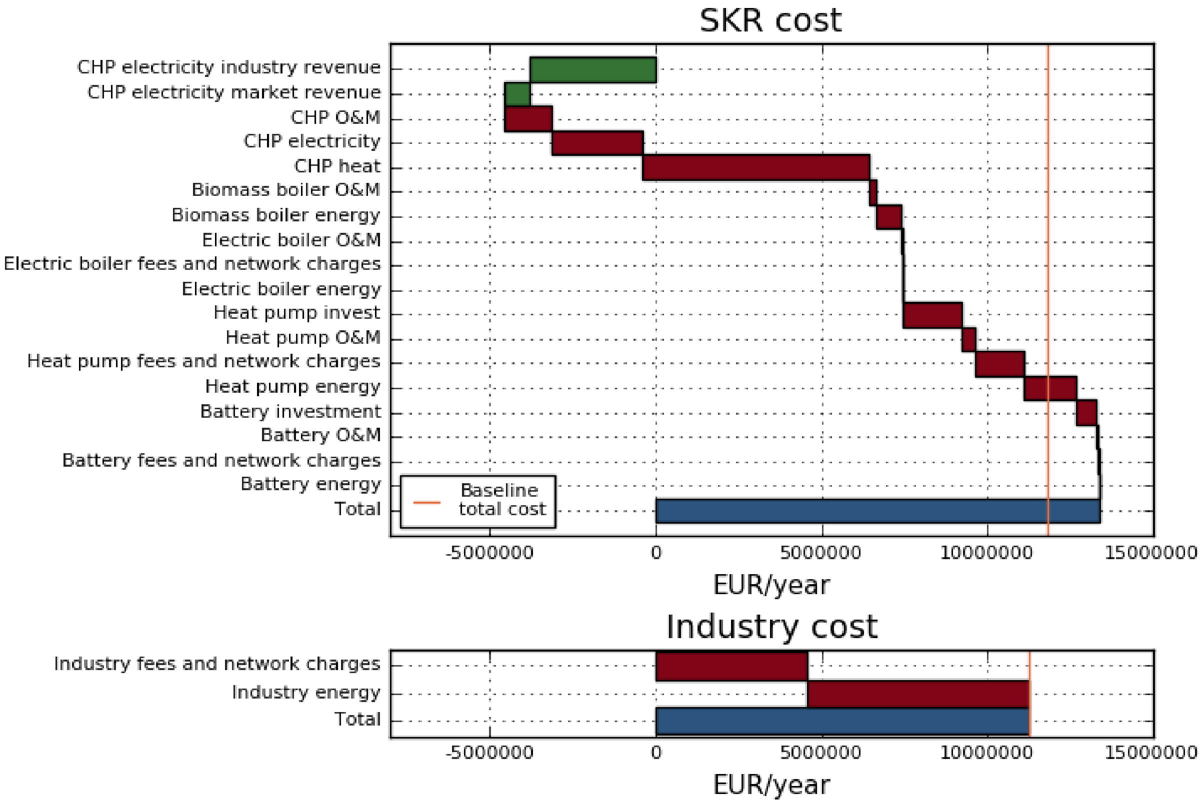

Figure 36: Annual cost components of Skellefteå Kraft and the industry in the scenario with the industry located at a different location than the CHP.

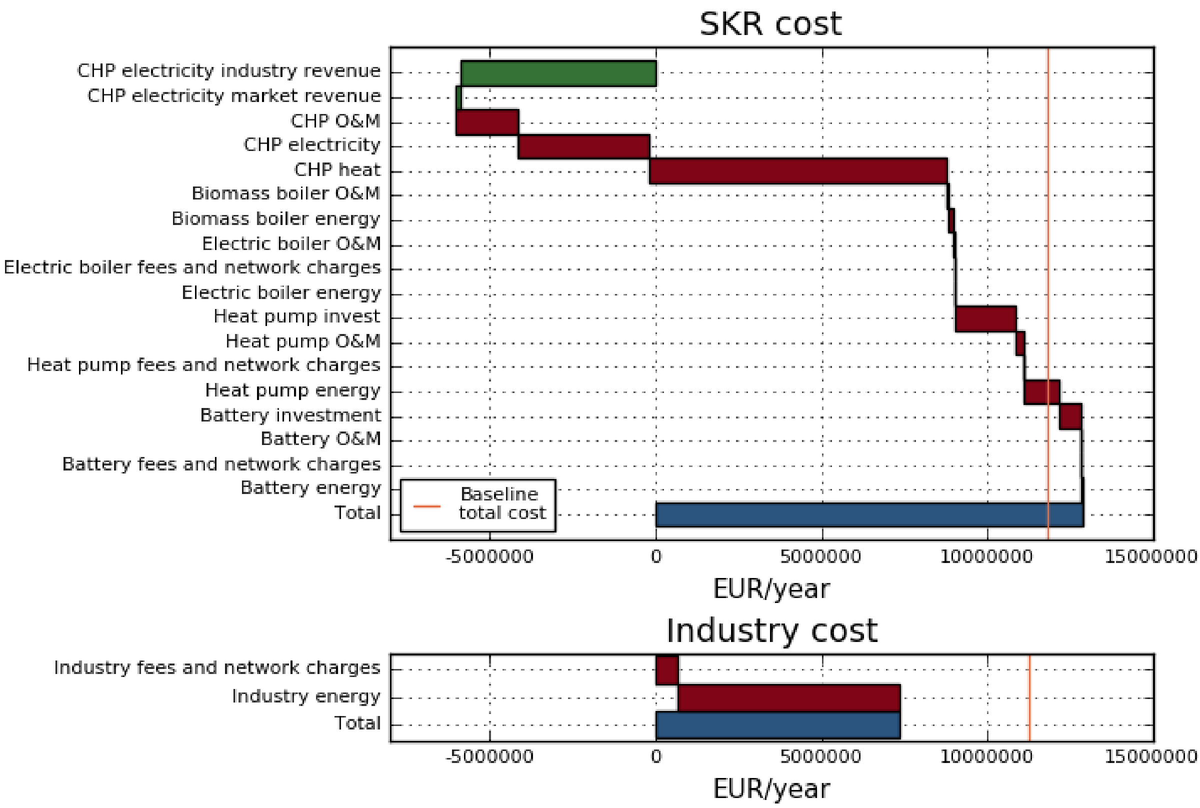

Figure 37: Annual cost components of Skellefteå Kraft and the industry in the scenario with the industry located at the CHP location.

The individual annual cost components in the advanced future scenario with the new technologies located at the CHP site are shown in Figure 37. Here even more electricity from CHP production is sold to the industry and barely any energy is placed on the wholesale market. Compared to the other location scenario CHP production is increased and heat pump operation decreased. This is due to the fact that in this configuration energy tax and network charges can be avoided when the industry demand is served directly by the CHP electricity output. Since more electricity output also means more heat output the heat pump does not have to be operated that much. When considering the investment cost of the new technologies this scenario still results in higher cost for Skellefteå Kraft compared to the baseline. The industry on the other hand can significantly reduce its energy procurement cost by avoiding energy taxes and network charges.

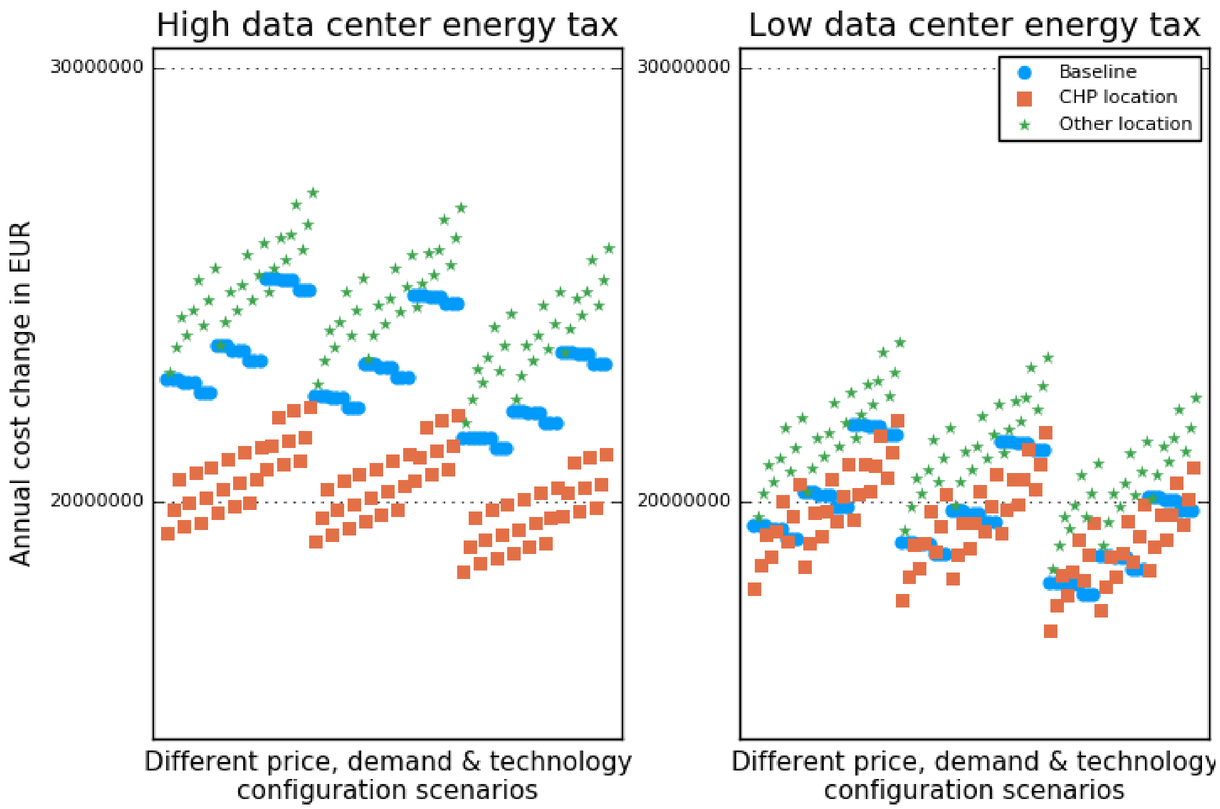

Figure 38: Total annual cost (SKR and industry) in different scenario configurations for different industry energy taxes.

Of course the results shown above can look different for different scenario configurations. However, with the assumed investment cost the advanced scenario with a different location than the CHP location almost always results in higher cost than the baseline scenario. This can also be seen in Figure 38, showing the combined annual cost of Skellefteå Kraft and the industry for different scenario configurations. Here only the results for an industry size of 20 MW are illustrated.

The economic efficiency of the scenario with the new devices and the industry located at the CHP location depends mostly on the assumed industry energy tax. While a lot of benefit can be generated in all demand and price scenarios with a high energy tax, for a low energy tax this is more sensitive to the other price parameters. If the energy tax is lower, less cost can be avoided by directly using the electricity from the CHP compared to the baseline scenario.

4.3.3 Acceptance and the Pareto criterion

In Figure 37 it can already be seen the benefits for the industry are higher than the additional cost of Skellefteå Kraft with the new cooperative scenario compared to the baseline. Thus, the combined costs of these market players are reduced and a win-win situation can be achieved by shifting some of the benefits from the industry to Skellefteå Kraft. Of course the combined benefit is significantly lower with a low industry energy tax, because in this case already the baseline costs of the industry are significantly reduced. This is illustrated in Figure 39 and Figure 40, respectively.

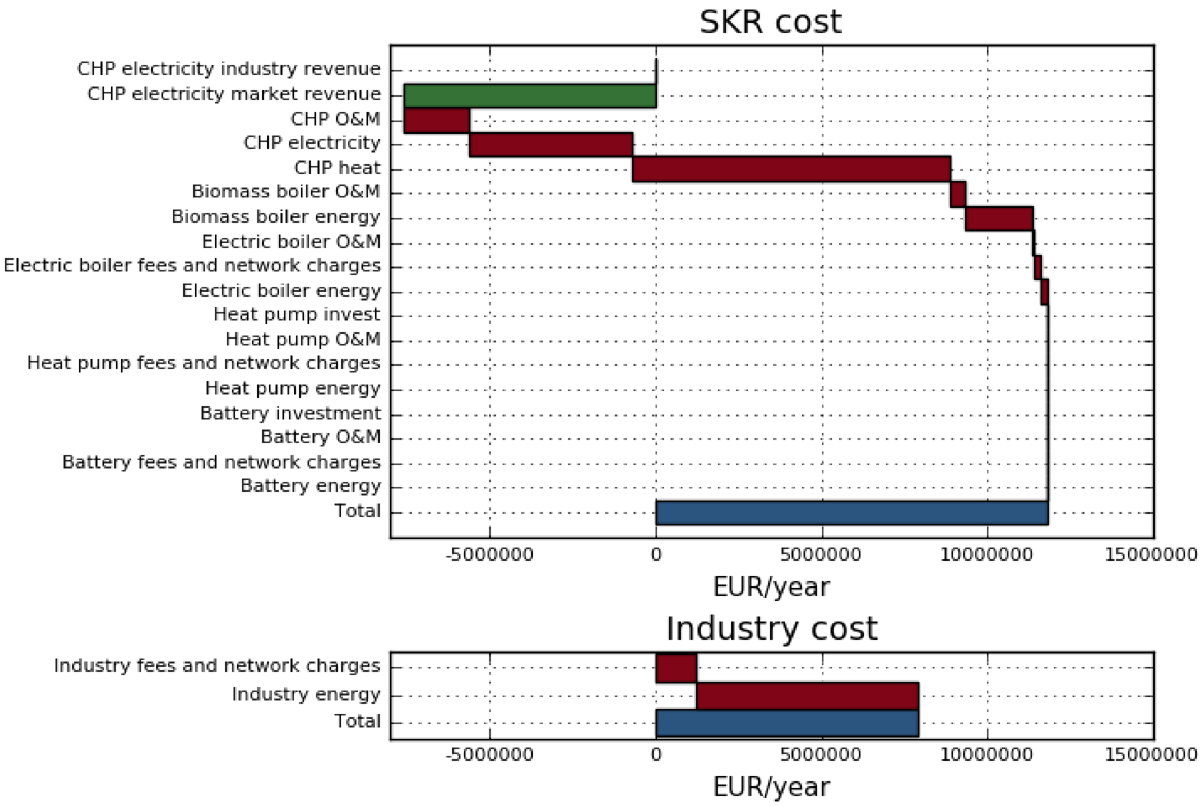

Figure 39: Annual cost components of Skellefteå Kraft and the industry in the baseline scenario with low industry energy tax.

However, if the new technologies are located at the CHP location, both energy tax scenarios result in lower total cost compared to the baseline. Thus, by shifting some of the additional cost from Skellefteå Kraft to the industry a win-win situation could be achieved with the advanced cooperative business model in these specific scenarios. Figure 41: Cost change for Skellefteå Kraft and the industry depending on the additional electricity tariff to be paid to Skellefteå Kraft in the scenario with the industry located at the CHP location.Figure 41 shows the cost change of Skellefteå Kraft and the industry compared to the baseline if a tariff is paid by the industry to Skellefteå Kraft in addition to the wholesale market price. The vertical red lines indicate the interval for an additional tariff, which both players can benefit with. Naturally, this interval is significantly with the high energy tax, which allows higher total benefits. The points where the two lines in Figure 41 cross show the tariff, which yields equal benefits for both stakeholders. Such an interval or such a point can be found in all scenarios that result in a reduction of total costs compared to the baseline, i.e. in all scenarios, where the orange squares are below the blue circles in Figure 38. This is the case in 374 of 486 (77%) scenarios with the industry located at the CHP site and in 18 of 486 (4%) scenarios with the industry located somewhere else.

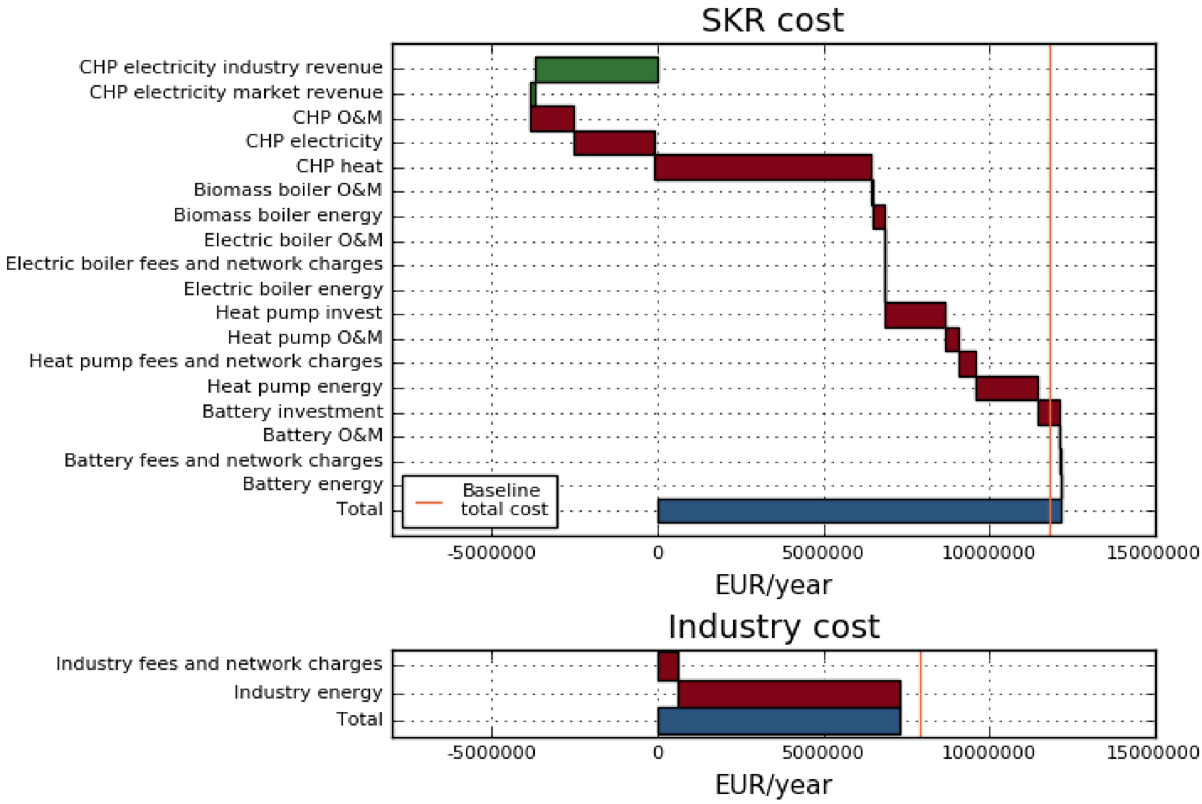

Figure 40: Annual cost components of Skellefteå Kraft and the industry in the advanced scenario with the industry located at the CHP site and a low industry energy tax.

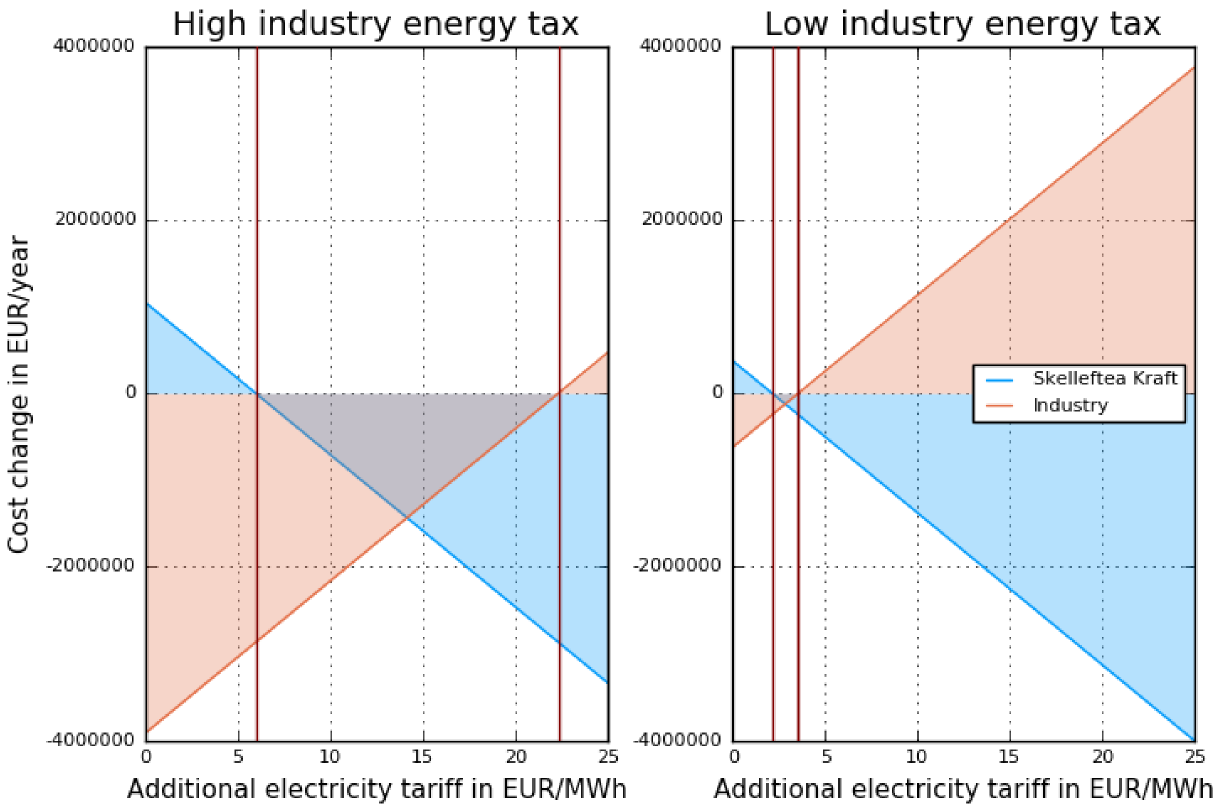

Figure 41: Cost change for Skellefteå Kraft and the industry depending on the additional electricity tariff to be paid to Skellefteå Kraft in the scenario with the industry located at the CHP location.

4.4 Conclusions and recommendations

- Using the waste heat of an energy-intensive industry with a heat pump can help to significantly reduce biomass usage for the heat production in Skellefteå.
- If a heat pump is installed it replaces the biomass-fired boiler as the second heating option after the CHP. If the industry is not located at the CHP site the heat pump even provides the base load during the summer months, because the electricity production of the CHP is not that beneficial for the industry.
- Considering both, the electricity demand of the industry and the heat production of Skellefteå Kraft, the implementation of the hybrid cooperative business model would reduce the carbon footprint in Skellefteå.
- The efficient heat pump in combination with the waste heat from the industry is a cheap heating source on an operational level. However, when investment costs of the heat pump and the battery are considered, SKR is confronted with higher annual heat production cost.
- Depending on the location of the industry, a significant cost reduction for the electricity procurement of the industry can be achieved. Thus, the CHP site is the preferable location. Here, electricity taxes and network charges can be avoided by directly using the electricity produced by the CHP.
- Thus, if the industry is located at the CHP site win-win situations among the two players, Skellefteå Kraft and the industry can be achieved.
- A high industry tax would provide more incentives for a cooperative business model among Skellefteå Kraft and the industry, because more benefit could be achieved by avoiding this tax. In general, however a high energy tax is also a major barrier for the investment in power-to-heat technologies.

5 Future scenario in Ulm

The future scenario for the Ulm demonstration site tackles the same issue as the corresponding today's scenario and tries to find a hybrid solution for dealing with PV surplus in LV network branches locally. Thus, this scenario is also strongly related to use case 3 "Optimal asset management and extension planning of distribution grids" and use case 4 "Maximizing local consumption of remote self-generation"

5.1 Scenario and business model description

The future scenario in Ulm considers the same low voltage network branch as the today's scenario and the same issue of dealing with PV surplus. Three possible approaches have been identified in Section 3 to tackle increasing PV feed-in in distribution grids:

1. Do nothing: Curtail feed-in and accept loss energy from a renewable energy source.
2. Grid reinforcement: Invest in a more powerful transformer to be able to feed in more PV surplus to the medium voltage network.
3. Increase local usage of PV surplus.

This use case investigates a central hybrid alternative to the distributed power-to-heat solution in the first use case. In contrast to the today's scenario, in the future scenario in Ulm the customers connected to the respective low voltage network branch are assumed to have a district heating connection instead of individual heating solutions, as illustrated in Figure 42.

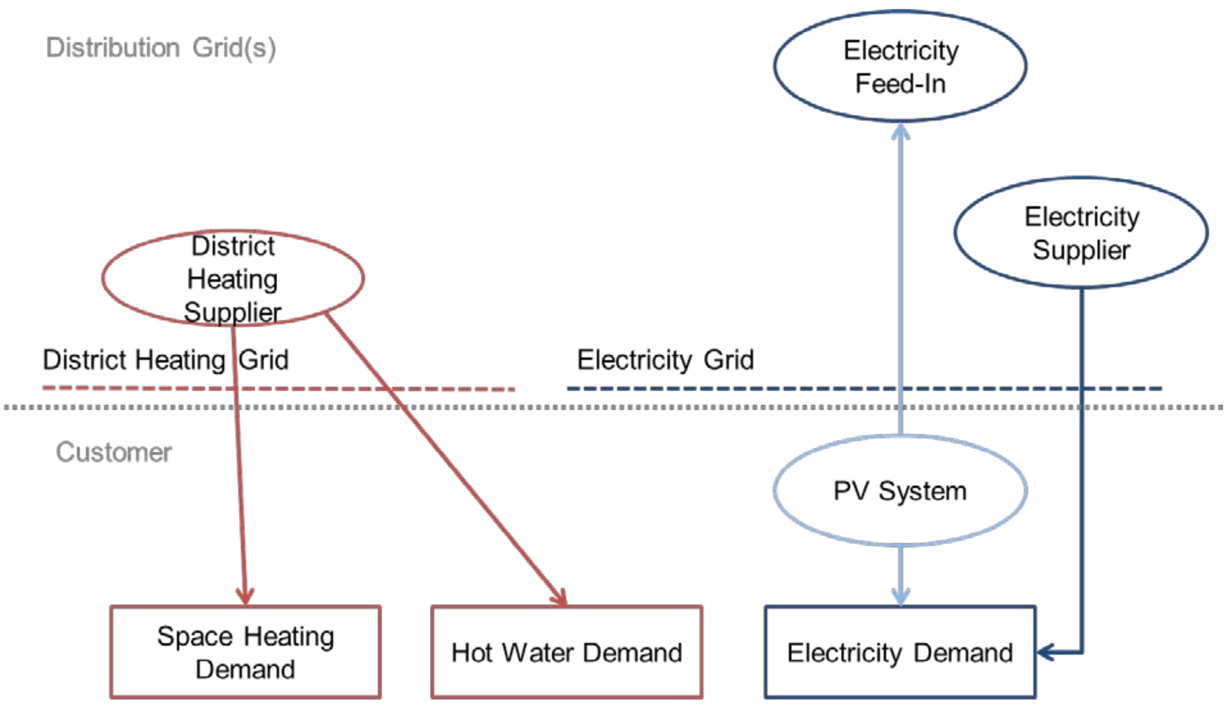

Figure 42: Conceptual overview of the energy supply in the baseline of the future scenario in Ulm

Under these circumstances the question arises, whether a central solution for the power-to-heat coupling point is more efficient than the distributed approach from the today's scenario. Firstly, due to economy of scales, a more powerful electric boiler is, in general, relatively[3] cheaper than distributed smaller devices. Furthermore, no energy production, conversion or storage devices would have to be installed remotely at the end users' sites, making ownership structures, operation and control less complicated.

The idea of the future scenario in Ulm is to install a central electric boiler in the area of Einsingen, being able to take up most of the customers PV surplus. Furthermore a central thermal storage is added in order to tackle the temporal mismatch of PV supply and heat demand. Both technologies can feed the district heating grid and, by this means, help to save alternative fuels used for heat production. Consequently, fuel cost can be saved by the district heating provider.

An additional benefit is created for the electricity distribution system operator by avoiding investment cost for network reinforcements (in this case an upgrade of the MV/LV transformer) or cost for compensating PV customers for shedding their PV feed-in. The PV customers, on the other hand, may lose part of their revenue from PV surplus feed-in. Depending on the value of the lost PV surplus, the cost of the alternative heating source and the necessary or avoided investments, a cost reduction for the energy supply chain in the considered system can be achieved. In this case, cost can be shifted among the three considered players to create win-win situations.

Another advantage of the central approach in the future scenario is the fact that the controller only needs to control the electric boiler and the thermal storage and does not have to coordinate the operation of multiple distributed devices. Figure 43 illustrates the basic idea of the future scenario in the Ulm demonstration site.

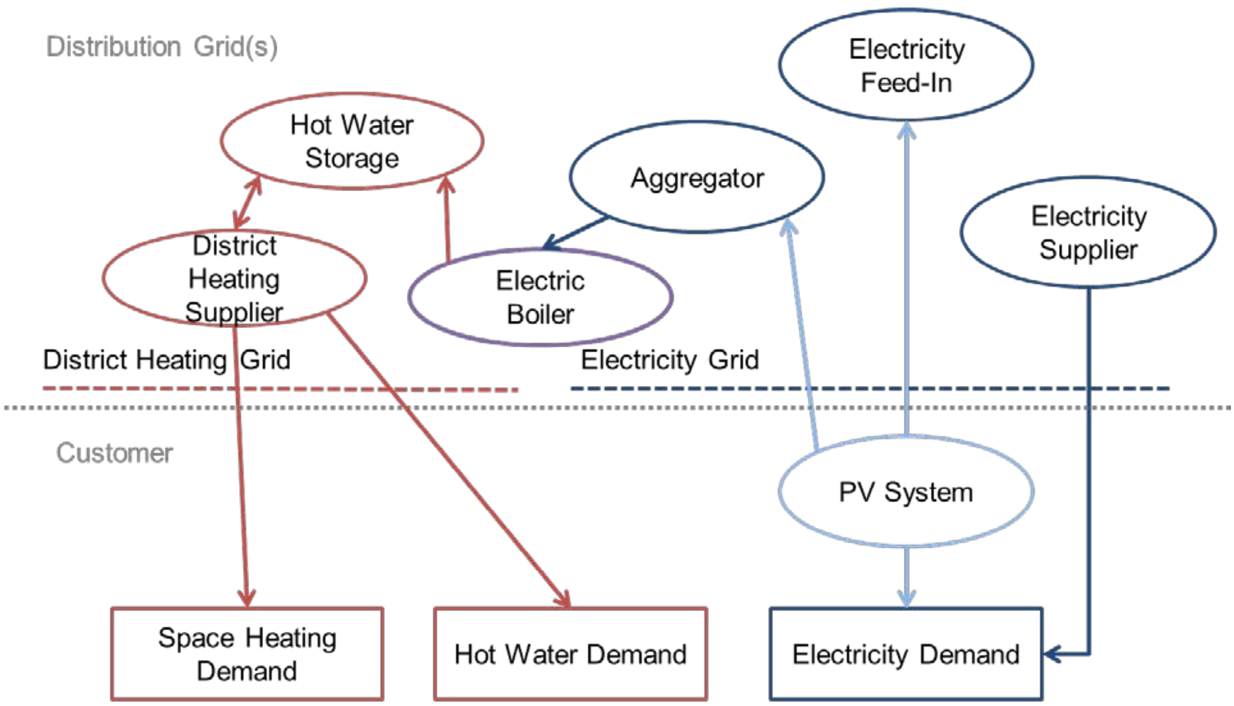

Figure 43: Conceptual overview of the energy supply in the advanced future scenario in Ulm

[3] i.e. per MW of nominal capacity.

5.2 Economic Modelling

Detailed effects of different operational control strategies investigated by WP5 are described and evaluated in Deliverable D5.3.2 [4]. Technical implications of different control strategies on the network and key parameters like the voltage violation are investigated by the Co-Simulation environment in WP4 and presented in Deliverable D4.3.2 [2]. The economic investigations assume control strategies with perfect foresight and rather focus on the implications of the business model for different market participants.

5.2.1 Mathematical Model

The mathematical model for this scenario is based on the methods presented in the formal framework in Deliverable D2.2 [5]. It is a linear optimization model minimizing the total cost for the district heating suppliers' heat production. The options for heat supply are the operation of the newly installed electric boiler, the thermal storage and alternative existing heat production plants, which are not specified in detail, but assumed to have fix heat production cost. Thus, the electric boiler can either be operated when PV surplus is available or when electricity prices, grid tariff and energy tax are below the alternative heat production cost. Thus, in general, the additional electric boiler and the thermal storage will reduce the annual heat production cost of the District Heating supplier for the area of Einsingen.

Three different control strategies are analysed for the electric boiler in this investigation, differing in the objective function of the optimization model:

Max local: This control strategy has the highest share of local usage of the PV surplus. This is achieved by setting the cost of PV surplus for the electric boiler operation zero in the objective function. Thus, whenever PV surplus is available in the low voltage network branch and there is demand for heat, the electric boiler will be activated.

Min cost: In this control strategy the PV surplus is valued with the current electricity spot market price in the objective function of the district heating operator. Note that it has been assumed here that no network charges have to be paid for electric boiler operation. The reasons for this assumption are, on the one hand, that the new electric boiler represents a means to solve issues in the electricity network and, on the other hand, that it would not be operated at all when including network charges because of low alternative heat production cost of 30-40 EUR/MWh.

Opt: This control strategy is to some extent a balance of the two above. It minimizes the cost by valuing the PV surplus, customers could have otherwise sold, with the spot market price in the objective function of the district heating supplier. The cost of the energy that would have been curtailed otherwise, however, is set zero.

5.2.2 Model Scaling

The data for electricity demand and heat demand, electricity spot market prices and tariffs are the same as the data used in the today's scenario for Ulm (c.f. Section 3.2.2). The data for the district heating tariff in Ulm is taken from [20] and listed in Table 28.

Table 28: Customer tariffs for district heating in Ulm

Type	Variable [ct/kWh]	Fixed [EUR/year]
District heating tariff	**4.996**	**587.10**

5.2.3 Sensitivity analyses

Table 23 shows the different parameter variations that are considered by the economic model. This yields a total of 324 different configurations for the model that optimizes the heat production of a district heating supplier over one year on a quarter-hourly level.

Table 29: Parameter variation scenarios considered by the economic model

Parameter	Variations			
Electric boiler size	*60%*	*80%*	*100%*	of 1.3 MW
Storage size	*60%*	*70%*	*80%*	of 6.5 MWh
Alternative heat production cost	*30*	*35*	*40*	EUR/MWH
Control Strategy	*Max local*	*Min cost*	*Opt*	
PV installation scenario	*PVSQ* (233 kWp)	*PV50* (1385 kWp)	*PV75* (1853 kWp)	*PV100* (2183 kWp)

5.3 Results

The detailed technical results of the co-simulation framework and the effects of the new electric boiler on the low voltage electricity network are presented in [2] and [4], respectively. This section will focus on the economic results and the impact of the new hybrid technologies on different market participants in the energy supply chain in the considered low voltage network branch in Einsingen, Ulm. In the following results for the scenario parameters listed in Table 30 are presented in detail.

Table 30: Parameters of the scenario investigated in this section

Parameter	
Electric boiler size	***80%***
Storage size	***70%***
Alternative heat production cost	***35***
PV installation scenario	***PV75***

The load duration curves of the transformer in the considered low voltage network branch are illustrated in … for different control strategies compared to the baseline scenario. It can be seen that the ***Max local*** control strategy minimizes the feed-in into the medium voltage network, i.e. the area below the zero axis. However, it is agnostic to issues in the local low voltage grid. This is also true for the ***Min cost*** control strategy, which results in the highest feed-in and PV surplus losses. The ***Opt*** control strategy, on the other hand, minimizes the area below the negative transformer rating line, which corresponds to the amount of energy from PV production that would have been curtailed.

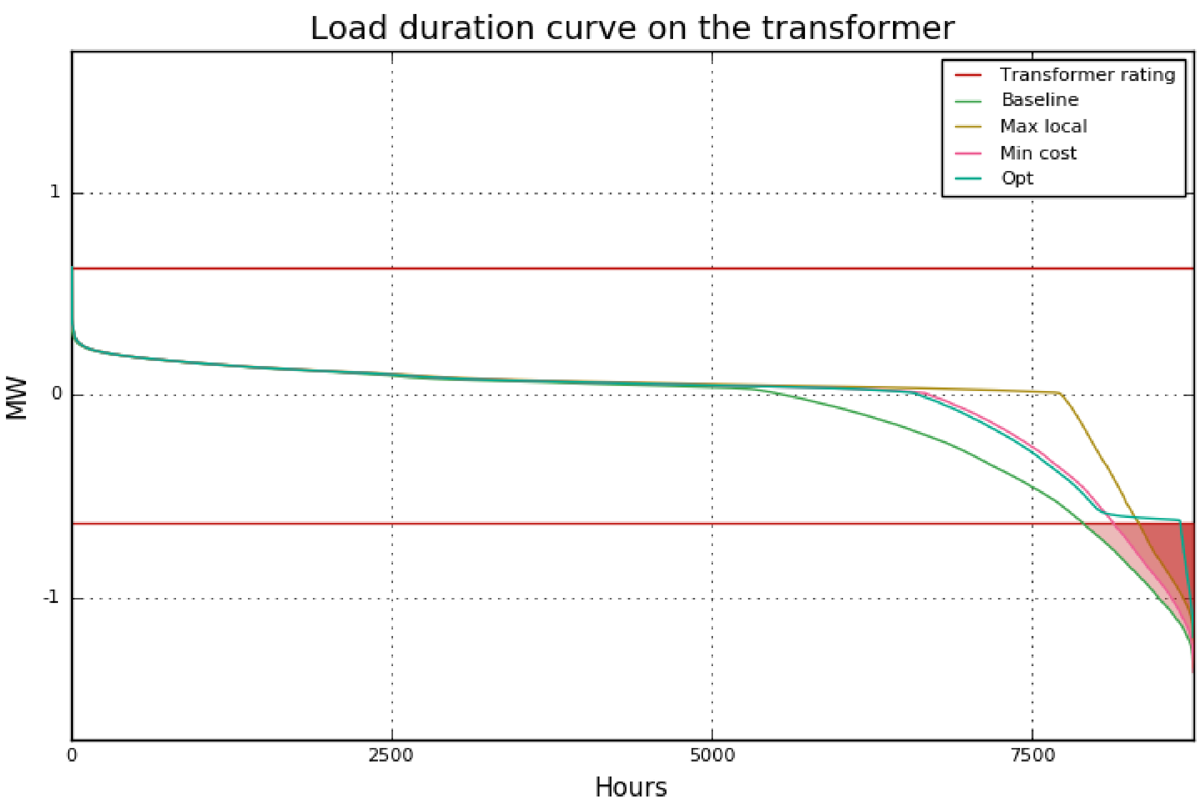

Figure 44: Load duration curves on the MV/LV transformer for different control strategies.

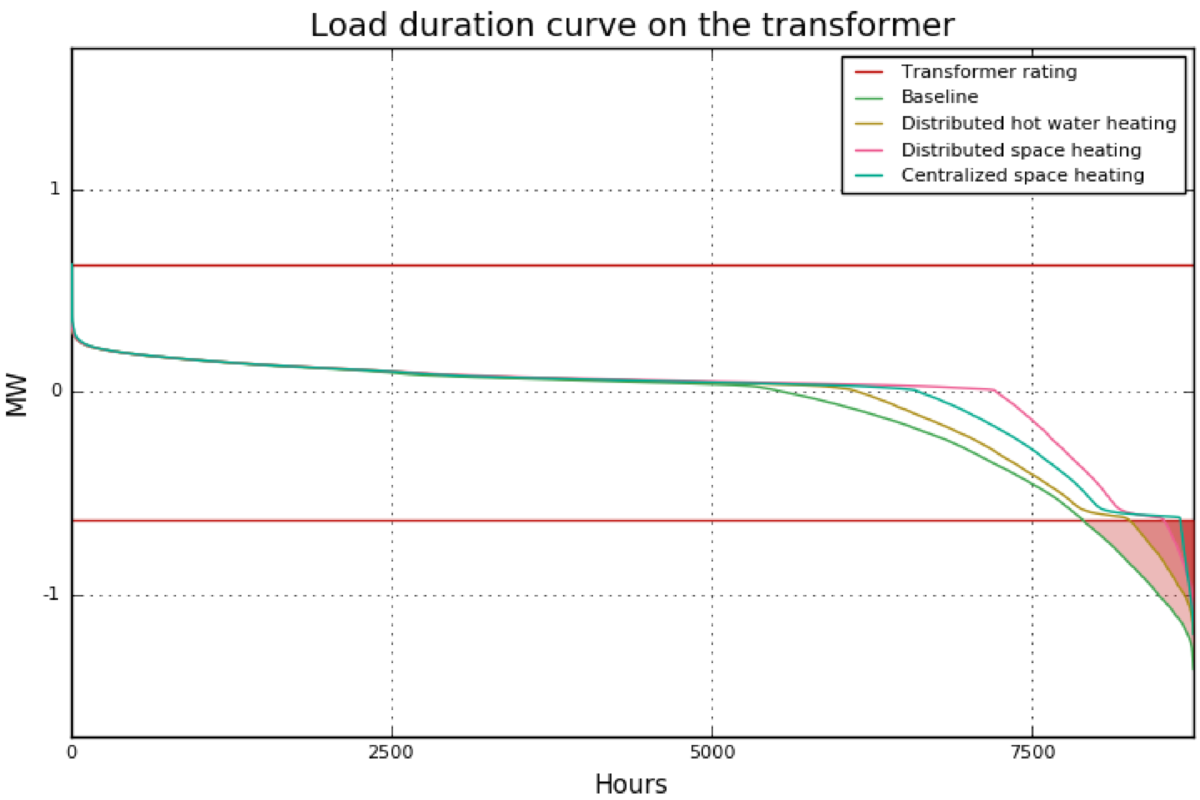

Figure 45: Load duration curves on the MV/LV transformer for different scenarios.

Figure 45 shows the load duration curves on the MV/LV transformer in Einsingen In different scenarios. The green curve represents the baseline scenario. The yellow line shows the load duration curve in the today's scenario in Ulm. This situation can be further improved by using distributed electric boilers for space heating as well, which is illustrated with the pink load duration curve. The blue curve indicates the result of the future scenario in Ulm, i.e. with a central electric boiler and the ***Opt*** control strategy. Here less PV surplus is used locally than in the distributed space heating scenario, but nevertheless the PV curtailment is further reduced. By comparing Figure 44 to Figure 45 it can be seen that with the current that the ***Max local*** control strategy would result in higher local usage than the distributed space heating scenario. Note that both today's scenarios are using a distributed ***Opt*** control strategy. The reason for them yielding higher local usage than the central ***Opt*** control strategy is that the operational opportunity costs of the individual heating systems in the today's scenario are significantly higher than the opportunity cost of 35 EUR/MWh of the district heating system.

5.3.1 Fossil fuel savings and greenhouse gas emissions

The usage of the energy production from local PV generation with different control strategies is shown in Figure 46. All three control strategies result in a significant increase of local usage of PV production (440 – 800 MWh/year) and a reduction of excess PV curtailment compared to the ***Baseline*** scenario.

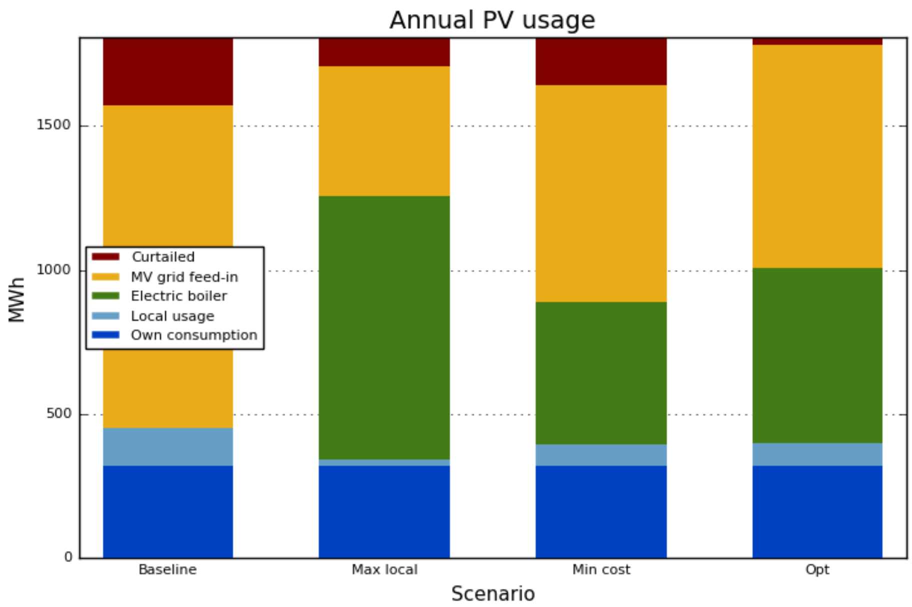

Figure 46: Usage of annual local PV generation with different control strategies.

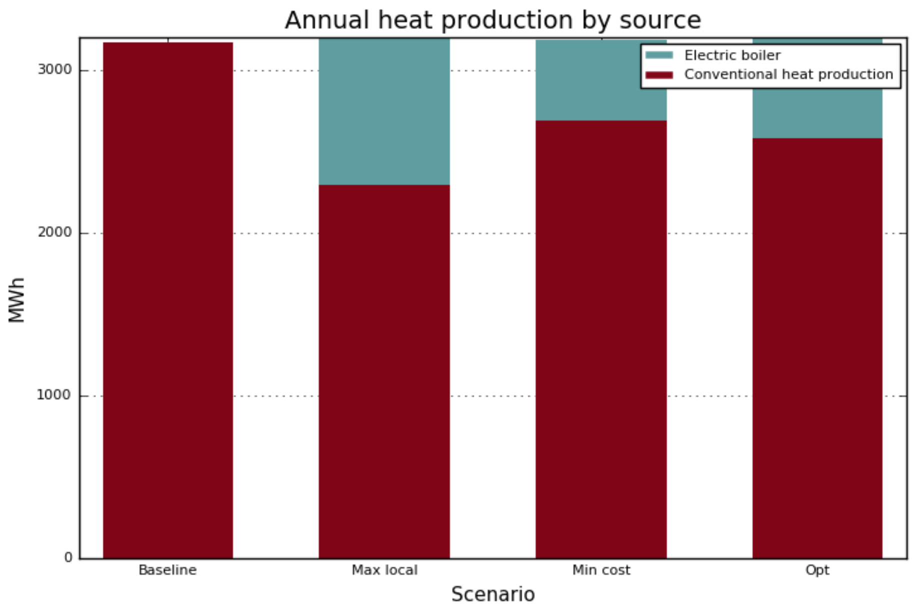

Figure 47: Annual heat prudoction by source in different scenarios.

The electric energy used by the electric boiler is from renewable local excess PV generation, which is produced in a carbon-neutral way. Thus the greenhouse gas emissions are reduced according to the displacement of the alternative heat production and depending on its fuel source mix. Hence, the ***Max local*** control strategy achieves the highest reduction of green-house gas emissions and the ***Min cost*** control the lowest.

5.3.2 Cost

As already discussed in the today's scenario, increasing the local usage of PV surplus prevents the customers with PV systems from potentially selling this energy on different energy markets. Thus, the electricity spot market price is used to value the energy produced by PV systems at a certain time. Depending on the regulatory framework, either the electricity distribution system operator has to remunerate the customers with PV systems for the energy curtailed due to network restrictions, or this energy represents lost potential revenue of the customers.

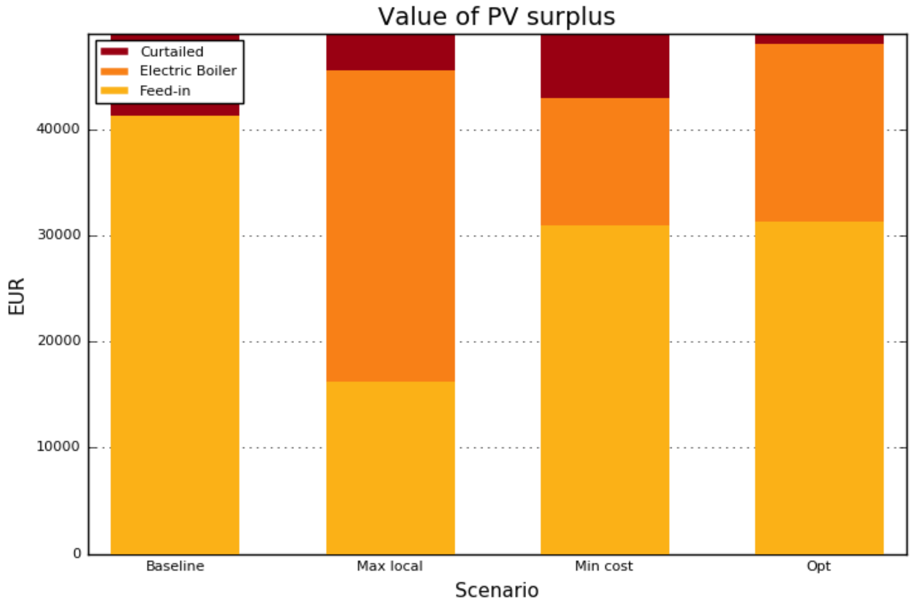

Figure 48: Value of annual local PV surplus by usage with different control strategies.

The value of various components of the local PV surplus is illustrated in Figure 48 for the different control strategies. The yellow area represents the value of the energy that is sold on the electricity spot market and is a sure revenue for the PV customers in Einsingen. The red area is the value of the electricity from PV systems that has to be curtailed due to network restrictions. This is either a revenue not made by the PV customers or remuneration costs for the electricity distribution system operator. If it is assumed that the costs of the system operator are passed on to the customers via the network charges, this remuneration would have to be paid by all customers in the end. The orange area represents the value of the PV surplus used to operate the electric boiler in different scenarios. It is subject to the business model design between the PV customers and the district heating system operator, whether and to what extent the customers get remunerated for this energy by the district heating system operator. The implications of different business model designs for different market participants will be treated in section 5.3.3. For now it can be stated that the different control strategies generate a value by reducing the amount of energy from PV surplus that would have been curtailed in the ***Baseline*** scenario.

In order to further clarify the above statement Figure 49 shows the annual operational cost of heat production for the customers connected to the district heating grid in Einsingen for different control strategies. In the ***Baseline*** scenario the total heat is provided by the existing heating source of the district heating grid, and hence all operational heat production cost is connected to it. In the other scenarios different shares of this cost is replaced by the operational costs related to the newly installed electric boilers. This cost contains general operational and maintenance cost and the cost for the electricity used to operate the electric boiler. The value of the electricity is shown as the blue areas in Figure 49 and divided into two parts. The darker part represents the value of PV surplus that would have been otherwise sold on the electricity spot market by the PV customers and the brighter part is the value of the energy that would have been otherwise curtailed.

Table 31: Annual operational benefit generated by different control strategies

	Max local	Min cost	Opt
Cost reduction in heat production	-150 EUR	3500 EUR	2400 EUR
Value of otherwise curtailed PV production	4350 EUR	1750 EUR	6850 EUR
Total	**4200 EUR**	**5250 EUR**	**9250 EUR**

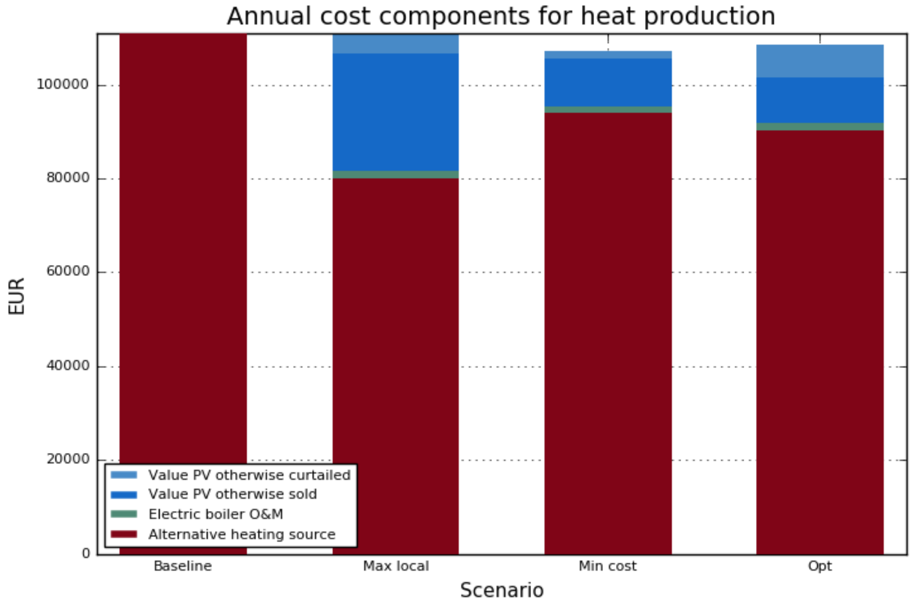

Figure 49: Annual operational cost of heat production with different control strategies.

The additional value, generated by the different control strategies consists of two components. The first component is the cost reduction in heat production due to replacing the existing heating source with electricity from PV surplus that is cheaper during these hours. This component is the difference of the total bar heights to the baseline bar height in Figure 49. The second component is the bright blue are in Figure 49, the value of energy used that would have been otherwise curtailed. This is either paid to the PV customers by the district heating system operator and additional revenue for them or else it is further cost reduction for the district heating system operator.

The two components of the annual benefit generated by different control strategies and their sum are listed in Table 31. Assuming an internal rate-of-return of 5% this yields different maximal total investment costs of the electric boiler and the thermal storage for different economic lifetimes. They are listed in Table 32.

Table 32: Maximal total investment cost of electric boiler and thermal storage for different control strategies and different economic lifetimes

Economic lifetime	Max local	Min cost	Opt
10 years	EUR 32.500,-	EUR 40.500,-	EUR 71.500,-
20 years	EUR 52.500,-	EUR 65.500,-	EUR 115.200,-

Adding the annuities of typical values of electric boiler investment cost (130.000,- EUR/MW) and medium-scale hot water storage tanks (500,- EUR/m³), derived from [11], to the annual heat production cost would increase the cost compared to the baseline in all three control strategy scenarios, as shown in Figure 50.

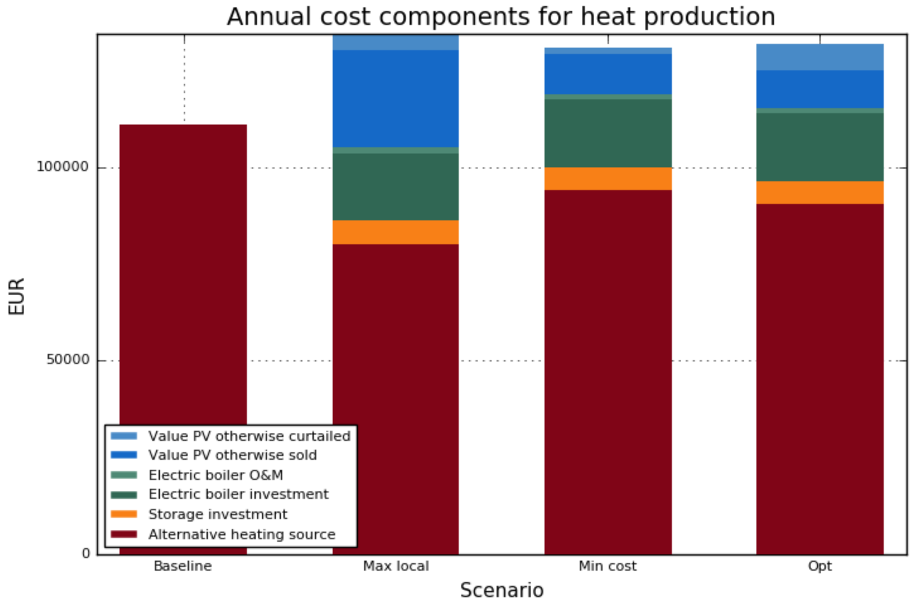

Figure 50: Usage of annual local PV generation with different control strategies.

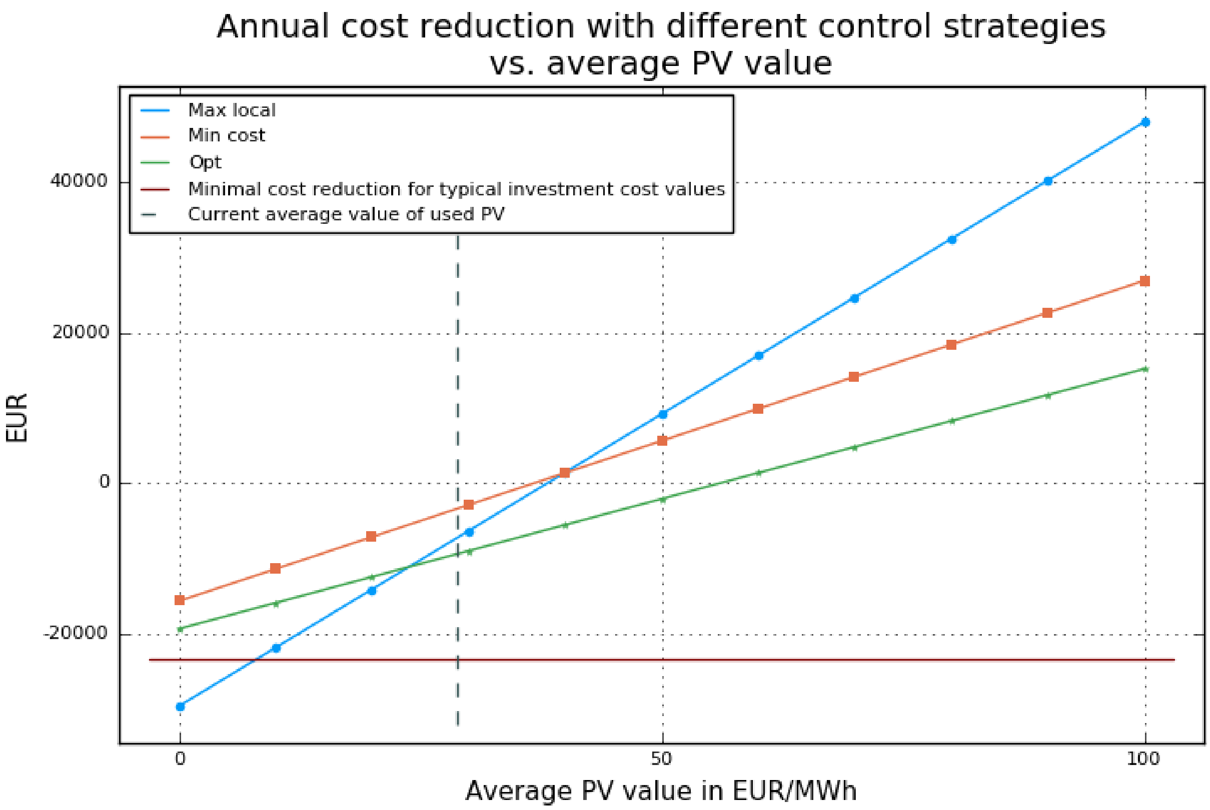

Figure 51: Annual cost reduction with different control strategies for different average PV values.

Thus, even without paying network charges an electric boiler investment would not be economical when considering typical investment cost. The profitability of the new hybrid coupling point, consisting of an electric boiler and a thermal storage, depends three key values:

1. ***The operational cost of the heat production source that is replaced by the electric boiler:*** This cost id assumed between 30 and 40 EUR/MWh for the district heating system in the future scenario, which is quite low compared to the operational cost of the individual heating systems in the today's scenario. Thus the cooperative control strategy in the today's scenario can generate more annual benefit than the different control strategies in the future scenario.
2. ***The value that is given to the local PV surplus:*** The less local PV surplus is valued, the less expensive one MWh of heat produced by the electric boiler becomes. On the other hand, less benefit is generated by the reduction of PV curtailment as well. Figure 51 shows the annual operational cost reduction with different control strategies depending on different average values for local PV surplus. It can be seen that for lower PV surplus values the ***Max local*** control strategy is the optimal strategy and for higher values the ***Min cost*** and the ***Opt*** control strategy are more economical. The ***Min cost*** control strategy results in worse global results than the ***Opt*** control because it only considers the cost reduction from the heat supplier's point-of-view and neglects transformer loading and PV curtailment.
3. ***The investment cost of the electric boiler and the thermal storage:*** Of course the business model gets more economical if the investment costs of the newly installed devices are reduced. Figure 52 shows the annual cost change for different investment cost.

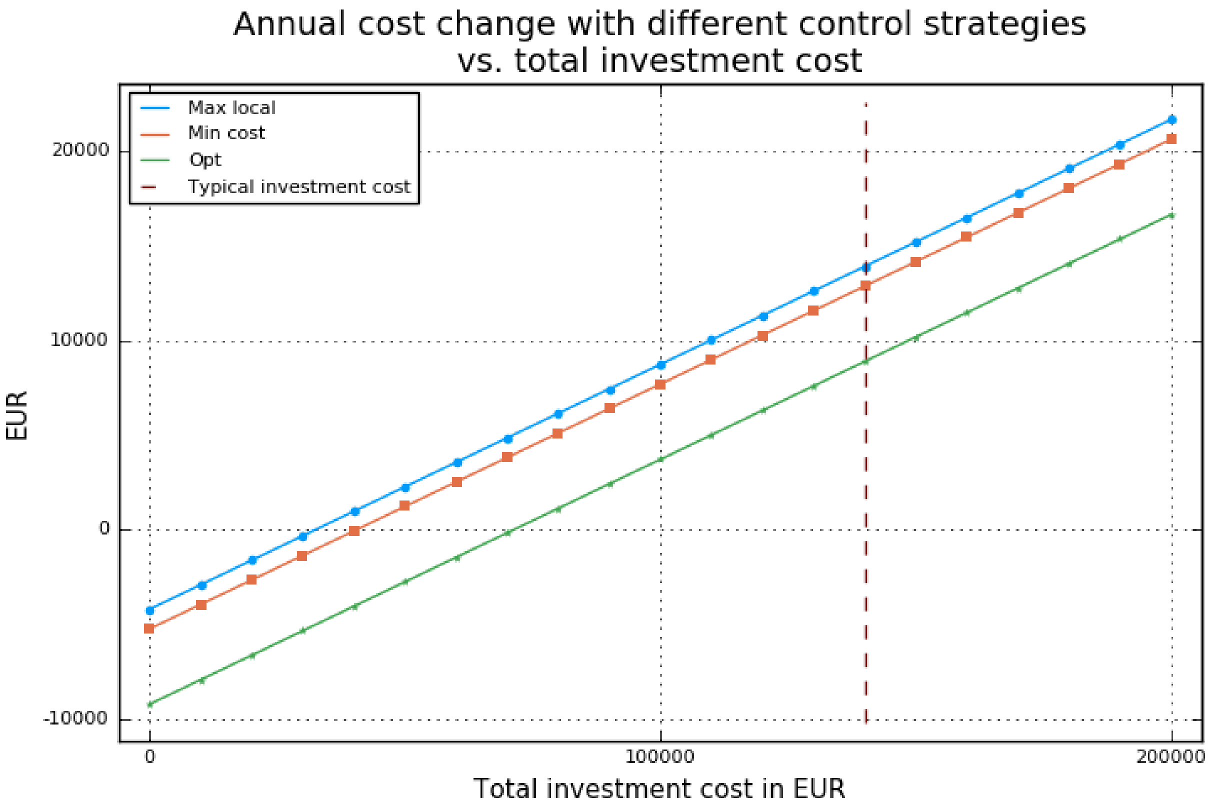

Figure 52: Annual cost change with different control strategies for different total electric boiler and thermal storage investment cost

5.3.3 Acceptance and the Pareto criterion

The Pareto criterion requires that all considered market participants have less or equal annual cost with the novel hybrid business model than in the baseline scenario. Naturally that is only possible, if a global annual cost reduction of all market participants is achieved. Thus, for this consideration investment cost for the electric boiler and the storage of 70.000 EUR and the implementation of the ***Opt*** control strategy are assumed.

Depending on different business model frameworks among the district heating network supplier and the customers, PV customers may be remunerated for the loss of revenues caused by the electric boiler operation. If total investment cost of 70.000 EUR are assumed, a total benefit of 1.500 EUR is achieved, which corresponds to an annual benefit of 194 EUR. If it is assumed that half of this benefit is taken by the heat supplier and the rest of it is passed on to the customers, it depends on the tariff, the PV customers are granted, how this remaining benefit is distributed among the customers. This is shown in Figure 53. Here it is assumed that all other cost changes of the heat supplier than the 97 EUR are passed on to all customers via the variable district heating tariff (reduction or increase). It can be seen in Figure 53, that a PV tariff for electric boiler operation between 16 and 16.5 EUR/MWh would result in a win-win situation among heat supplier, PV and passive customers. Of course this interval would be increased if the heat supplier would take less of the annual benefit and decreased otherwise.

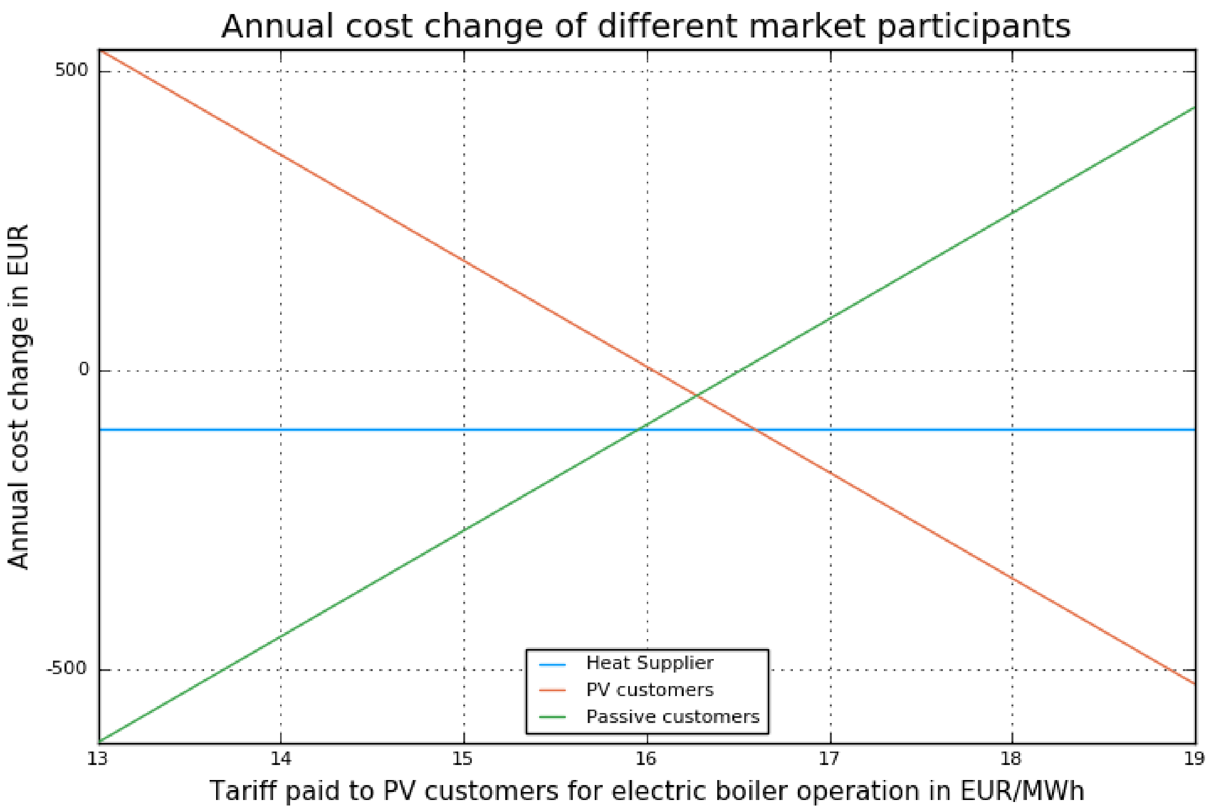

Figure 53: Annual cost change for different market participants with the Opt controll strategy depending on the tariff offered to PV customers

5.4 Conclusions and recommendations

- All three control strategies result in a significant increase of the local usage of PV, ***Max local*** being the most and ***Min cost*** the least effective.
- The ***Opt*** control strategy achieves the lowest values of PV curtailment.
- The value generated by the cooperative business model consists of two components:
  - The value of not curtailed and thus additionally usable PV generation.
  - The cost reduction in heat production by saving alternative heating sources.
- Thus, the economic efficiency of the cooperative business model depends very much on the value that is given to the PV surplus: A lower value would decrease the first component and increase the second, and vice versa for a higher value.
- With typical investment cost values the cooperative business model leads to significantly higher total system cost.
- The central approach in the future scenario in Ulm achieves significantly worse than the decentral business model in the today’s scenario in Ulm, because in the future district heating scenario the alternative heating cost are lower compared to the individual heating cost of the customers in the today’s scenario. Thus, less benefit can be generated by replacing this alternative heating source.

6 Conclusions

In both demonstration sites it has been shown that a hybridization of the energy supply chain and a stronger coupling of the energy distribution networks can reduce the usage of fossil fuels. This is mainly achieved by using more of the intermittent renewables on the electricity domain. The usage of hybrid coupling points provides more flexibility – especially for the electricity network – and, thus, can be an important tool to further increase the share of renewable energy sources in Europe's energy system.

With the investigation of the tailor-made case studies it has been shown that the development of hybrid cooperative business models can either be motivated by the heat domain (reducing fossil fuel usage for heat production in Skellefteå) or by the electricity domain (increasing the local usage of local renewables and relieving the electricity distribution system in Ulm). In both cases situations have been found, where synergies among the energy domains could be exploited and multiple market participants could benefit from tighter coupling of the energy domains.

Nevertheless, for some use cases strong assumptions regarding e.g. the regulatory framework (especially in Ulm) had to be made for the investigation of hybrid cooperative control strategies and major barriers have been identified. Firstly, the distribution system operator, who would in many cases be the predestined market participant to implement such cooperative hybrid business models has a lack of incentives to promote them: The allowed revenue of a distribution system operator is linked to the asset value of the distribution network in the regulative process and, thus, investing in capital-intensive grid reinforcement is more beneficial from his point-of-view. Secondly, the distribution system operator, who has detailed information about key operational figures in the network, is not allowed to trade energy and thus cannot operate coupling points in most situations. In this case a third party like a aggregator would be required, which makes business model development more complicated, because finding additional benefits for a new market player is not trivial.

Furthermore, the major barrier from an economic perspective for the implementation of hybrid business models is given by the network charges and electricity taxes for power-to-heat technologies. Even if in many situations it could be beneficial for both energy domains (excess renewable surplus in the electricity grid and cheap heating source in the district heating network), network charges and other electricity fees make such a cooperation economically inefficient. Thus, the business models having been identified as the most economic for the involved market participants are the ones aiming to avoid these charges by operating behind system boundaries (e.g. CHP and electric boiler or heat pump at the same location in Skellefteå).

Another lesson learned from the validation of the benefits in the demonstration sites is the fact that most business models are very sensitive to input parameters like energy prices and demand development and that, while some general conclusions could be drawn, most hybrid cooperative business model implementations would require a comprehensive location- or country-specific investigation.

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