Subsidies or cost-reflective energy tariffs? Alternative pathways for decarbonizing the residential sector and implications for cost efficiency[1]

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ABSTRACT

This study assesses alternative energy technologies (i.e., PV and battery systems, electric heat pumps, hybrid gas heating with solar thermal energy) in terms of profitability and CO_2 emissions, for the case of two simulated typical households living in detached houses in Germany. Under the status-quo regulatory framework, the energy transition in the heating sector is fostered through grants for replacing old heating systems, whereas PV generation is fostered by feed-in tariffs and indirect subsidies for self-consumption. This study considers an alternative regulatory scenario with a more market-oriented approach, finding that a CO_2-oriented reform of energy surcharges and taxes, as well as a reform of network charges, can support a more cost-efficient energy transition in the residential sector. The paper concludes with a discussion of the consistency, cost efficiency and effectiveness of past and current policies underpinning the energy transition in the residential sector.

Keywords: heat pump, solar thermal energy, carbon pricing, tariff design, heating sector, prosumers

NOMENCLATURE

Abbreviations	
BAU_sub	business-as-usual scenario
BES	battery energy storage
CC&Ene_ref	scenario with regulatory reforms
COP	coefficient of performance
DCF	discounted cash flow
DHW	domestic hot water
EEG	Renewable Energy Sources Act
EEL	Exogenous electrical load
FiT	feed-in tariff
GB	gas condensing boiler
HES	home energy system
HGS	hybrid GB–STE system
HH1	simulated household 1
HH2	simulated household 2
HP	electric air-to-water heat pump
IPH	investment planning horizon
LCOE	levelized cost of electricity
LPG	*LoadProfileGenerator*
LPOE	levelized profit of electricity
LROE	levelized revenue of electricity
PV	photovoltaic
RET	renewable energy technology
STE	solar thermal energy
VAT	value-added tax

1. INTRODUCTION

The heating sector represents a major part of Germany's decarbonization challenge, accounting for approximately half of all German energy consumption and currently relies predominantly on fossil fuels [1], especially gas-based heating systems [2]. As of 2021, approx. 1.2 million heat pumps were in place compared to approx. 14 million gas heating systems [2]. In 2022, following the escalation of the Russo-Ukrainian conflict, the German Federal Government strengthened the ambitions for the decarbonization of the heating sector, setting the target for 6 million heat pumps to be installed by 2030, and committing to the goal of renewable energy meeting 65% of new heating systems' energy needs from 2025[3]. At the time of writing, the Federal Government is considering bringing forward the implementation of the "65% requirement" for new heating systems to the beginning of 2024 [4].

The German Energy Transition has traditionally focused on the electricity sector, with centralized promotional schemes that reward the feed-in of electricity from renewable energy technologies (RETs) into the electricity grid. In contrast, the heating sector is much more

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fragmented, making the coordination and organization of the transition to low-carbon technologies much more challenging [5]. Moreover, there are severe difficulties with implementation capacities in the heating installation sector and also uncertainty arising from the shift in the government's strategy from the promotion of hybrid gas heating systems to a much greater focus on heat pumps [6]. Low-carbon heating systems have received subsidies in Germany since 1999, under the market incentive program, involving subsidies for technologies [7]. As of 2022, subsidies fostered the replacement of old boilers with entirely low-carbon heat technologies. These included heat pumps and biomass systems, as well as hybrid systems, such as gas condensing boilers (GB) with solar thermal energy (STE) systems. Subsidies were designed to cover a percentage of the investment costs associated with a new heating technology ranging from 30% of investment costs for a hybrid GB–STE system (HGS) to 35% for a heat pump and other low-carbon heating systems. Subsidy rates increased by 10 percentage points when technologies replaced old oil boilers, whereas additional heating-related investments (e.g., aeration systems) received a grant covering 20% of the costs [8]. While there is recognition that a mix of technologies will be required, it is certain that an increasing share of electricity-based technologies will be central to the decarbonization of heat [9] and the regulatory framework should reform levies on renewable electricity, thereby making electricity for heating more affordable [1]. Over the last decade, in comparison to other European households, German retail consumers have been charged very high electricity rates [10], but below average rates for natural gas [11]. As a result, gas-based heating has been until recently the predominant technology. While Germany has often been portrayed as a pioneer of the energy transition, this example demonstrates that the country's energy policy has actually been rather inconsistent.

This paper considers how alternative regulatory scenarios affect the adoption and optimal operation of alternative home energy systems (HESs), consisting of photovoltaic (PV) and battery energy storage (BES) systems, an electric air-to-water heat pump (HP), or a hybrid gas heating with solar thermal energy (HGS). We investigate (i) the extent to which technology adoption and operation are incentivized and (ii) how the households' financially optimal decisions perform in terms of CO_2 emission savings. This study considers a business-as-usual (*BAU_sub*) scenario, based on retail energy tariffs, including PV feed-in tariffs (FiTs), available in the first half of 2021[2] to residential consumers and the aforementioned subsidies for new heating systems. By building upon the regulatory scenarios devised in [12], this study then considers *CC&Ene_ref*, namely the best performing scenario both in terms of carbon emission reduction and grid-friendly operation of energy technologies [12]. *CC&Ene_ref* consists of two policy reforms. The first regulatory shift is a fundamental reform of electricity network charges, in which infrastructure costs are recovered through dynamic capacity-based charges rather than flat volumetric charges, while coincident demand and feed-in charges provide an incentive to relieve the power grid during high-demand and high-injection periods, respectively. Such alternative price signals aim to improve cost reflectivity of network charges and to promote a more efficient use of the grid. The second regulatory shift consists of an energy reform, by which all energy taxes and surcharges are abolished and replaced with a uniform CO_2 pricing mechanism. Such a reform leads to an increase in natural gas retail prices and in average wholesale electricity prices. At the same time, dynamic retail prices are adopted, meaning that the high variability in wholesale electricity prices incentivizes load shifting to periods of low-carbon electricity generation. Therefore, dynamic retail power prices become more cost-reflective, in that they reflect the real-time cost of generation, which also price in the cost of CO_2. Similarly, for electricity exported to the grid, the fixed feed-in tariff is replaced by dynamic market prices. Overall, such policy reforms result in significantly lower average volumetric electricity retail prices which tend to both improve the profitability of electrical heating and to incentivize a grid- and low-carbon-oriented operation of BES and HPs.

Therefore, this paper assesses how the decision of two simulated households, which need to renovate their HES, is affected: (i) by the status quo of flat energy tariffs and subsidy schemes of *BAU_sub* and (ii) by the alternative regulatory scenario *CC&Ene_ref*, consisting of dynamic, grid- and carbon-oriented energy tariffs, while lacking any sort of subsidy scheme. The results of this analysis have implications that go beyond the German case and concern the cost efficiency, the consistency and the effectiveness of energy policies in a broader context, especially for countries with a high share of fossil fuel-based heating systems.

[2] Energy prices soared to unprecedented levels in the second half of 2021. If such price level becomes permanent, this will affect significantly the financial assessment of HESs. In this paper, we assume households face the market conditions that existed at the start of 2021, with respect to energy costs, technology costs, system costs and inflation.

2. MATERIALS AND METHODS

2.1 DATA & ASSUMPTIONS

Table 1 – Yearly energy demand and PV generation of the 2 simulated households

Load type	**HH1**	**HH2**
EEL (kWh)	4,903	3,283
DHW (kWh)	2,659	2,741
Space Heating (kWh)	12,895	12,895
PV generation (kWh/ kW_p)	1,088	1,088

This study is based on a set of data and assumptions, which are described in detail in [12]. While the methods and most of data sources of this paper are the same as in [12], important additions of this study are the assessment of HGS and the analysis of a second simulated household. Moreover, major differences concern the assumed costs for heating-system-related adaptations and renovations of the detached house, as, in this study, such costs are minor and reduce, in particular, the investment costs of the new GB-based heating system. In this section, the most relevant data sources and assumptions are summarized. Synthetic load profiles of electricity, domestic hot water (DHW) and space heating demand refer to two households based in Essen, Germany, living in 150m^2 single-family homes equipped with an old gas boiler. The load profiles were generated by the *LoadProfileGenerator* [13-15] (LPG), a tool that simulates the demand behavior of residential energy consumers. Within the tool, a predefined household type (i.e., *CHR27 Family both at work, 2 children*) was selected, in order to represent a typical potential adopter of these energy technologies. In this regard, households with 2 children are likely to own their dwelling and to live in detached or semi-detached houses [16]. Moreover, PV self-generation may be more profitable for such households, as a result of their relatively high self-consumption potential (in comparison to smaller households) [17]. By means of the LPG, two simulations were carried out, which differed structurally only in terms of the energy efficiency of electrical devices: HH1 is a household with random devices, whereas HH2 is a household with energy-saving devices.[3] Consequently, the annual energy demand of the two simulated households differs systematically with respect to the exogenous electrical load (EEL), namely the electrical demand, which excludes the additional, endogenous and optimizable HP demand. The two simulated households differ marginally also in terms of DHW demand, due to random household behavior. The space heating demand does not vary between the two simulations, as it depends only on external temperature profiles and building characteristics, which are equal for both simulated households. Temperature and PV generation profiles were obtained from the online-tool *Renewables.ninja* [18-20] for the location of Essen, Germany, and refer to the year 2019.[4] Table 1 reports the annual energy demand, as well as the electricity generation per kW of installed PV capacity, for the two simulated households. For the assessment of grid-related carbon emissions and for the design of the alternative regulatory scenario, i.e., *CC&Ene_ref*, estimates of hourly intensity of grid electricity, real-time network conditions, data on carbon allowances prices, as well as hourly wholesale electricity prices, were used in accordance with [12]. The time series all refer to the year

Table 2 – Structure of electricity and gas tariffs, dynamic rates are reported as a range of values. Negative values indicate revenues. (Including VAT, based on [12])

Scenario	**Charge type**	**Std. power**	**HP power**	**Feed-in (<10 kW)**	**Feed-in (>10 kW)**	**Natural gas**
BAU_sub	Flat volumetric (ct/kWh)	26.07	19.41	-8.16	-7.93	4.63
	Fixed (€/year)	118.52	66.46	-	-	136.69
CC&Ene_ref	Flat volumetric (ct/kWh)	2.84		-	-	6.16
	Dynamic volumetric (ct/kWh)	[-7.62 ,21.53]		-[-7.62,18.08]		-
	On-peak capacity (€/KW/month)	5		5		-
	Off-peak demand (€/KW/month)	2.5 (min 2.6 kW)		-	-	-
	Fixed (€/year)	40.34	66.46	-	-	136.69

[3] In the *LoadProfileGenerator* one can select different types of households, using electrical devices that belong to different categories (e.g., fridge, TV set, etc.). Within each device category, several devices with different levels of energy intensity are available. A household with energy-saving devices uses exclusively the most energy-efficient device within each device category (e.g., the most energy-efficient fridge available in the tool). A household with random devices uses, in contrast, electrical devices that may or may not be the most energy-efficient devices within their respective device category [15].

[4] For the production of PV generation data, system losses were set at 15%, panels' inclination and azimuth were set at 30° and at 180° (i.e., southward facing), respectively. Such input values were based on [21].

2019.[5] For the estimation of wholesale electricity prices in *CC&Ene_ref*, a national CO_2 price of 125 €/t is assumed, as such a level has been deemed sufficient for the implementation of a revenue-neutral reform of energy taxes and surcharges [22]. The integration of high CO_2 prices into wholesale electricity prices feeds through into retail prices, yet this effect is far outweighed by the impact of the removal of surcharges and electricity taxes, with average retail electricity prices, in fact, falling. Injection into the grid is remunerated with the same dynamic wholesale prices, except for VAT and the concession fee which are added only to retail withdrawal rates. Moreover, the replacement of volumetric network charges with capacity-based charges results in a further reduction in volumetric retail electricity prices under this regulatory scenario. In particular, a 2-tier demand charge is levied on grid imports during on-peak (i.e., coincident demand) and off-peak monthly peaks, respectively. For grid exports, in contrast, only an on-peak feed-in charge is levied. Moreover, the feed-in charge is levied, if and only if, coincident injection surpasses the annual coincident demand peak. In other words, it is assumed that the grid users already pay their fair share of network costs exclusively through demand charges, as long as their monthly coincident feed-in, which occurs typically during summertime, is below their maximum annual coincident demand, which occurs typically during wintertime (for a detailed description of and discussion on this reform of network charges see [12]). For the two scenarios, the structure of electricity and gas tariffs is given in Table 2.

Table 3 – Costs of heating systems (including VAT)

	GB	HGS	HP
Investment costs (€)	9,400	19,100	23,820
Operating costs (€/y)	420	525	440
Grant in BAU_sub (€)	0	5,460	7,447
Grant in CC&Ene_ref (€)	0	0	0

In this study, the replacement of the old heating system in the detached house is considered: the old gas boiler can be replaced either by (i) a HGS or (ii) a HP. The costs and available grants for these two alternatives are based on [23] and reported in Table 3: the HP installation involves significantly higher investment due to the same HP costs, the additional storage and the need for additional building-related adaptions (i.e., new pipes and radiators). Moreover, the household can invest in an optional PV system and in BES. The investment, replacement and operating costs for PV and batteries are given in Table 4. Four different PV systems and four different BES systems were considered, in order to cover a range of system sizes typically installed by residential prosumers (see, e.g., [24] with respect to PV and [25] with respect to BES). This also allows to analyze the trade-off between economies of scale and sizing based on self-consumption potential. With respect to the heating systems, based on the simulation of [12] and on [23], we assume that the GB and the old GB systems have a final efficiency (i.e., the ratio between supplied heating energy and input energy in terms of natural gas) of 97.3%, and of 80.4%, respectively. By means of STE the natural gas demand of the GB is assumed to be reduced by 22%, based on [26]. The HP has a variable coefficient of performance[6] (COP) and additional storage losses, as its load can be deferred by means of two heat storage devices for DHW and space heating, at 35 °C and 55 °C, respectively. Consequently, its final efficiency depends on its operation. In particular, it decreases in *CC&Ene_ref* as dynamic power rates provide incentives to shift HP load to times with low electricity prices (see [12] for details). All HES' components are assumed to have a lifetime of 20 years (except for the BES cells which can be replaced during the analysis period).

2.2 MODELING APPROACH

The modeling approach is described in detail in [12]. In summary, it consists of two modules, namely (i) an operation module and (ii) an investment module.

The operation module optimizes the energy dispatch of a given HES for a set of typical periods (i.e., four 8-day typical periods, one for each meteorological season), which reflect the first year of operation. It calculates the optimized dispatch of PV electricity and optimal operation of the HP and of the BES system, by implementing a rolling horizon approach in which optimizations within the same meteorological season are chained to each other.

The investment module considers the optimized energy dispatch, resulting from the operation module, and extends it over an investment planning horizon (IPH) of 20 years. It considers PV and battery degradation, as well as increase in prices due to inflation (except for FiTs) and the decline in the carbon emission intensity of grid electricity. In this regard, an annual inflation rate of 2% is considered, whereas emission intensity of grid electricity

[5] We consider the first half of 2021 and 2019 as two similar periods in terms of the general energy market condition. However, a harmonization of retail electricity tariffs between the two scenarios is also implemented, as such tariffs are based on data referring to these two different years (see [12] for details).

[6] E.g., with an outside air temperature of 2 °C, the COP to obtain water at 35 °C is 3.4. See [12] for a comprehensive overview of COP values.

is assumed to decline annually by 9%, in line with IEA projections [27]. The annual real discount rate is also set at 2% (from the household perspective). The investment module computes the financial performance in terms of tax-adjusted discounted cash flow (DCF), and impact on CO_2 emissions of each HES under the two regulatory scenarios. Moreover, tax-adjusted financial metrics, namely the levelized cost, levelized revenue and levelized profit of PV electricity (i.e., LCOE, LROE and LPOE) were also calculated, as such metrics allow for a straightforward understanding of the financial performance of PV self-generation. For a comprehensive overview of such financial metrics see [28].

Table 4 – Cost of PV and BES systems (Including VAT, based on [12])

	PV			
Nominal Power (kW)	5	7.5	9.9	15
Investment costs (€)	7,559	10,308	12,495	17,805
Operating costs (€/y)	150	175	200	250
	BES			
Nominal capacity (kWh)	3.3	6.7	10	13.3
Maximum power (kW)	3	4	5	5
Investment costs (€)	6,614	7,879	9,299	9,547
Operating costs (€/y)	0	0	0	0
Replacement costs (€)	900	1,800	2,700	3,600

3. RESULTS

This section reports:

- the financial performance, in terms of the DCF of net costs (i.e., the difference between energy and system costs and feed-in revenues) over the IPH.
- the impact on CO_2 emissions due to the operation over the IPH, in terms of net emissions (i.e., the difference between emissions caused by household energy demand and those displaced through PV feed-in), over the same period.

In *BAU_sub*, the status-quo scenario with subsidies for heating technologies, the HGS shows a significantly better financial performance than the HP when there is no PV capacity and when PV capacity is below 7.5 kW_p. For instance, in the case of HH1, the HGS-0-0[7] shows a DCF that is approximately 5% lower than that of the HP-0-0 (i.e., € 55,527 vs € 58,550, cf. Table 5). The results for HH2 show a similar pattern. From a PV capacity of 7.5 kWp, the HP performs better financially, because of higher self-consumption savings. Self-consumption savings reflect the high volumetric electricity rates in this scenario. For both households, the HP combined with a 15 kW_p PV system achieves the lowest DCF, i.e., € 51,207 for HH1 and € 50,104 for HH2. BES adversely affects financial performance, but there can still be non-financial motivations to adopt batteries (e.g., for the purposes of greater independence from the grid), which is why it is important to understand the impact of their operation. In *CC&Ene_ref*, investment grants are withdrawn and it is clear from Table 5 that the heat pump outperforms the hybrid system for both simulated households. This is because retail electricity prices (and, hence, the role of self-consumption savings) diminish in *CC&Ene_ref* thanks to the removal of volumetric network charges, surcharges and taxes. In the first year of the IPH, average standard-electricity volumetric rates fall from approx. 26.1 ct/kWh to approx. 12 ct/kWh. Deferrable HP load is optimized to further reduce the average withdrawal price, which is why average HP power rates fall from 19.4 ct/kWh to 10.7 ct/kWh (in the case of HP-0-0). The uniform CO_2 price (levied also on gas) coupled with the reduced retail electricity prices appears to shift the financial attractiveness clearly in favor of the HP. Moreover, despite the removal of grants for renewable heating technologies, the financial performance of HP-0-0 in *CC&Ene_ref* is slightly better than HGS-0-0 in the *BAU_sub* scenario (e.g., € 55,527 vs € 55,016 for HH1). This implies that the effect of the reduced retail electricity prices outweighs the effect of the withdrawal of subsidies. It must be noted that real-time price signals combined with the possibility of deferring the HP load allow for further savings: the HP can withdraw electricity during low-cost periods, while avoiding additional demand charges thanks to a peak-shaving strategy. However, the lowest DCF is still achieved in *BAU_sub* with HP-15-0 and GB-15-0, as the higher electricity costs are more than offset thanks to self-consumption savings and the investment grant for the HP, which is why the status-quo scenario may be financially superior from the perspective of households that both adopt PV and receive a grant for a heating system. Major differences between the two households arise when considering PV installation in *CC&Ene_ref*. For HH1, although PV is less profitable than in *BAU_sub*, the installation of the largest PV is still the most profitable option for each given heating system (i.e., HGS-15-0 with a DCF of € 56,892 and HP-15-0 with a DCF of € 52,356). For HH2, however, PV installation is never financially superior and the largest

[7] The composition of the HES is abbreviated, in this case HGS stands for the hybrid system as opposed to the HP, the first 0 stands for the kW_p of the PV system, whereas the second 0 stands for the capacity (in kWh) of the BES system.

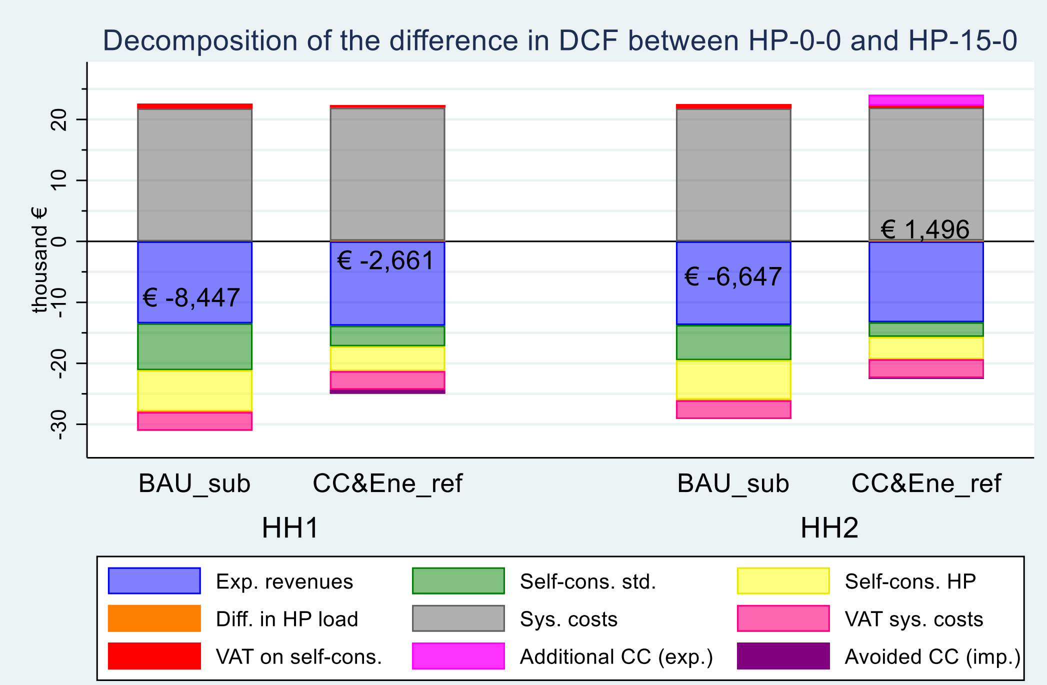
Table 5 – DCF (€) of HESs by household and regulatory scenario

			HGS					HP				
			BES (kWh)					BES (kWh)				
HH	**Scenario**	**PV (kW_p)**	0.0	3.3	6.7	10.0	13.3	0.0	3.3	6.7	10.0	13.3
1	*BAU_sub*	0	55,527	-	-	-	-	58,550	-	-	-	-
		5	53,868	57,457	57,254	57,425	57,107	53,947	57,925	58,002	58,741	58,630
		7.5	53,049	56,643	56,335	56,392	55,915	52,655	56,480	56,323	56,501	55,884
		9.9	52,066	55,633	55,224	55,217	54,701	51,406	55,149	54,880	54,680	54,171
		15	51,207	54,641	54,066	54,068	53,454	50,104	53,745	53,256	53,108	52,410
	CC&Ene_ref	0	58,417	61,591	61,824	62,423	62,445	55,016	58,248	59,198	60,111	59,899
		5	59,736	62,889	63,202	63,351	63,653	55,462	58,694	59,287	60,314	60,151
		7.5	59,142	62,335	62,756	62,805	62,503	54,780	58,006	58,564	58,968	58,966
		9.9	58,242	61,513	61,663	62,249	61,820	53,764	57,086	57,335	57,687	57,411
		15	56,892	60,690	61,492	61,924	61,572	52,356	55,971	56,657	57,178	56,697
2	*BAU_sub*	0	49,197	-	-	-	-	51,989	-	-	-	-
		5	48,540	52,227	52,193	52,580	52,671	48,579	52,923	53,343	54,172	53,837
		7.5	47,946	51,547	51,401	51,654	51,681	47,517	51,567	51,735	52,378	52,228
		9.9	47,135	50,654	50,395	50,735	50,768	46,421	50,338	50,436	50,833	50,400
		15	46,505	49,948	49,698	49,905	49,832	45,342	49,144	48,877	49,446	48,952
	CC&Ene_ref	0	52,800	56,115	56,681	56,967	56,759	49,139	52,478	53,047	54,285	54,395
		5	54,945	58,488	58,895	59,576	59,269	50,531	54,201	54,846	55,567	54,975
		7.5	54,721	58,879	59,281	60,211	59,935	50,147	54,156	54,937	55,301	55,229
		9.9	54,741	59,023	59,442	60,164	60,066	49,787	54,304	54,736	55,420	55,360
		15	55,745	59,973	60,390	60,969	60,550	50,635	55,101	55,726	56,436	56,009

PV has the worst performance. Such outcomes can be mostly explained by means of tax-adjusted metrics such as levelized cost, levelized revenue and levelized profit of electricity (i.e., LCOE, LROE and LPOE) from PV self-generation. For instance, in the case of a 15 kW_p for HH2 [8], the LCOE of the PV system amounts to 8.53 ct/kWh. The LROE of electricity exports is, however, lower in both scenarios, namely 7.93 ct/kWh in *BAU_sub* (namely the FiT) and 7.79 ct/kWh in *CC&Ene_ref*, meaning that the PV operator realizes a loss (i.e., a negative LPOE) when feeding electricity into the grid. Therefore, self-consumption savings are crucial for the profitability of PV self-generation. The LROE of self-consumption in *BAU_sub* is 29.13 ct/kWh for standard electricity and 21.70 ct/kWh for HP electricity, resulting in an average LPOE of 16.14 ct/kWh. When moving to *CC&Ene_ref,* the LROE drops to 11.97 ct/kWh for standard electricity and to 12.43 ct/kWh for HP electricity, resulting in an average LPOE of 3.72 ct/kWh. Given such a low level of LPOE associated with self-consumption, in contrast to HH1, a relative low volume of self- consumed electricity could not be sufficient to compensate for the losses deriving from electricity exports. This is the case for the PV systems smaller than 15 kW_p for which the discounted system costs are higher than the sum of discounted savings from self-consumption and revenues from exports (i.e., the discounted value of PV electricity).

In *CC&Ene_ref*, in the case of HH2 with HP-15-0 however, thanks to economies of scales (i.e., lower LCOE) the discounted system costs are lower than the discounted value of PV electricity, meaning that other factors are decisive to achieve a DCF € 1,495 higher for HP-15-0 in comparison to HP-0-0 (cf. Table 5). Figure 1 shows the contributing factors to the difference in DCF between HES with only a HP and HES with a HP and a 15 kW_p PV system. Such a difference can be interpreted as the profitability of PV self-generation. In the case of HH2 in

[8] Minimal difference (approx. 2%) in the LCOE of PV systems between households are due to the selection of typical periods and their corresponding level of PV generation. Typical periods are selected based on estimated energy costs deriving from individual household demand profiles, temperature and generation profiles, which is why they vary between households (for details see [12]).



Note: the values on the bars represent the sum of negative and positive contributions, i.e., a negative value indicates a lower DCF, namely a profitable PV installation.

Figure 1 – Decomposition of PV profitability

CC&Ene_ref, capacity charges play a major role: while PV adoption slightly reduces import charges (i.e., avoided CC), additional feed-in charges (i.e. additional CC) contribute to an increase in DCF by approx. € 1731. This makes the adoption of the 15 kWp PV financially sub-optimal, even when compared to smaller PV systems (cf. Table 5, where HP-9.9-0 achieves the lowest DCF among HP-PV systems, i.e., € 49,787). Such a high level of feed-in charges occurs because such charges are levied only on the additional monthly coincident feed-in peak above the annual coincident withdrawal peak. In this regard, HH1 avoids paying feed-in charges during summertime following its high coincident demand peaks during wintertime. HH2, in contrast, given its lower electrical demand and its subsequent lower coincident demand, incurs additional feed-in charges.

Table 6 reports the results in terms of carbon emissions over the 20-year IPH. For both scenarios and households, the HP is by far preferable in terms of CO_2 emission reduction. For instance, in the case of HH1, 67.4 t of emissions with a hybrid system vs 30.9 t with a HP that can be further reduced to 30.1 t thanks to the market-oriented operation in *CC&Ene_ref.* The additional adoption of a PV further reduces emissions, i.e., from a capacity of 9.9 kW_p for HH1 and of 7.5 kW_p for HH2, negative emissions are achieved, meaning that displaced emissions surpass demand-related emissions (e.g., -26.5 t in the case of HP-15-0 for HH2 in *CC&Ene_ref).* The co-adoption of a BES offers capacity for load shifting to low-carbon, low-cost periods, and feed-in shifting to high-carbon, high-cost ones, resulting in further CO_2 emission saving in *CC&Ene_ref*[9] (e.g., -29.2 t in the case of HP-15-13.3 for HH2).

Government grants in *BAU_sub*, which lead to similar, and, sometimes, better financial performance for the hybrid system compared to the heat pump, do not reflect the superior performance of the HP in terms of emissions. In this respect, we consider the cost in terms of DCF for each ton of avoided CO_2 emissions, by comparing the investment in a new HES to the adoption of a GB without STE, PV or BES. Such a "non-green" investment alternative would result in a level of carbon emissions over the 20-year IPH of 81.6 tCO_2 for HH1, and of 73 tCO_2 for HH2. In order to calculate the cost per avoided t of CO_2, also the DCF of the HES GB-0-0 was calculated. For HH1 the DCF amounted to € 52,028 and to € 50,325, for *BAU_sub* and *CC&Ene_ref,* respectively. For HH2 the DCF amounted to € 45,572 and € 44,540, for *BAU_sub* and *CC&Ene_ref*, respectively. Figure 2 reports the costs per avoided tCO_2 following the replacement or additional adoption of a given HES component. For HH1 in *BAU_sub*, passing from GB to a HGS entails a cost per

[9] In *BAU_sub*, in spite of flat power rates, batteries bring about a slight reduction in carbon emissions, because the charging occurs during periods of high PV generation, whereas discharging occurs when grid electricity is on average more carbon-intensive.

Table 6 – Net carbon emissions over the IPH (t) of HESs by household and regulatory scenario

			HGS					HP				
			BES (kWh)					BES (kWh)				
HH	**Scenario**	**PV (kW_p)**	0.0	3.3	6.7	10.0	13.3	0.0	3.3	6.7	10.0	13.3
1	*BAU_sub*	0	67.4	-	-	-	-	30.9	-	-	-	-
		5	49.9	49.8	49.5	49.4	49.4	13.2	12.9	12.7	12.7	12.6
		7.5	41.2	41.0	40.9	40.8	40.8	4.5	4.2	4.0	3.9	3.9
		9.9	32.8	32.7	32.5	32.5	32.5	-3.9	-4.2	-4.4	-4.5	-4.5
		15	14.9	14.9	14.8	14.8	14.8	-21.8	-22.1	-22.2	-22.3	-22.3
	CC&Ene_ref	0	67.4	66.7	65.9	65.4	65.1	30.1	29.2	28.6	28.2	27.9
		5	49.9	49.2	48.5	47.9	47.3	12.7	11.9	11.2	10.5	10.0
		7.5	41.2	40.5	39.7	39.0	38.4	4.0	3.2	2.4	1.8	1.1
		9.9	32.8	32.1	31.3	30.6	30.0	-4.5	-5.2	-6.0	-6.6	-7.2
		15	14.9	14.3	13.6	12.9	12.3	-22.2	-22.9	-23.7	-24.3	-24.9
2	*BAU_sub*	0	59.5	-	-	-	-	23.7	-	-	-	-
		5	42.9	42.7	42.4	42.4	42.3	6.8	6.5	6.3	6.1	6.1
		7.5	34.6	34.4	34.2	34.1	34.1	-1.5	-1.9	-2.0	-2.2	-2.3
		9.9	26.6	26.4	26.3	26.2	26.2	-9.4	-9.8	-10.0	-10.1	-10.2
		15	9.7	9.5	9.4	9.3	9.3	-26.4	-26.7	-27.0	-27.1	-27.1
	CC&Ene_ref	0	59.5	58.7	57.9	57.4	57.0	22.9	22.0	21.3	20.7	20.3
		5	42.9	42.3	41.6	40.9	40.1	6.4	5.5	4.7	4.1	3.6
		7.5	34.6	34.1	33.3	32.6	31.9	-2.0	-2.5	-3.3	-3.9	-4.6
		9.9	26.7	26.2	25.4	24.7	23.9	-9.8	-10.4	-11.1	-11.8	-12.4
		15	10.1	9.5	8.7	8.0	7.1	-26.5	-27.1	-27.7	-28.4	-29.2

avoided tCO2 of € 246.2. Moreover, given that, in this scenario, an investment grant is provided an additional 384.2 €/tCO_2 are financed by the government subsidy. By adding a 15 kW_p PV to the HGS, however, the DCF drops due to the profitability of PV self-generation (thanks to self-consumption savings), thereby resulting in a negative cost (i.e., an earning) of -82.3 €/tCO_2. Finally, by coupling a 13.3 kWh BES, the additional carbon emission reduction reach a cost of € 12,095 €/tCO_2, indicating that this is an extremely inefficient way to reduce emissions. Replacing the GB with the HP in *BAU_sub* entails significantly lower costs in comparison to the HGS, i.e., around 130 €/tCO_2 plus approx. 150 €/tCO_2 in investment grants for both households. The sharpest shift may, however, be observed when changing to *CC&Ene_ref*, where the HP achieves a cost per avoided tCO_2 of approx. € 91, whereas the HGS shows much higher values (€ 569.3 and € 610.4, for HH1 and HH2, respectively). In other words, a change to a more market-oriented regulatory framework makes the HP more cost-efficient in terms of carbon emission reduction in comparison to the HGS. Adding a PV system results in earnings for HH1 and additional costs for HH2 for the reasons discussed above. Finally, in this scenario, and with the HP, the additional coupling of BES entails very high costs per avoided tCO_2 (€ 1,658.6 and € 2,044.5 for HH1 and HH2 respectively). Such values, however, are far lower than those in *BAU_sub*, thanks to a low-carbon-oriented battery operation.

4. DISCUSSION

The design of the German energy transition in the heating sector has been inefficient in meeting the desired decarbonization goals. Given the available subsidies, HGS systems have, until very recently, enjoyed substantial financial support despite the fact that heat pumps can offer far superior performance on carbon emission reduction. Moreover, high electricity prices as opposed to comparatively low natural gas prices have contributed to the hitherto slow uptake of heat pumps in Germany – for example, in 2021, only ca. 154,200 heat pumps were installed in Germany, as opposed to 573,200 gas condensing boilers [29], which is inconsistent with the climate goals outlined by the German government.

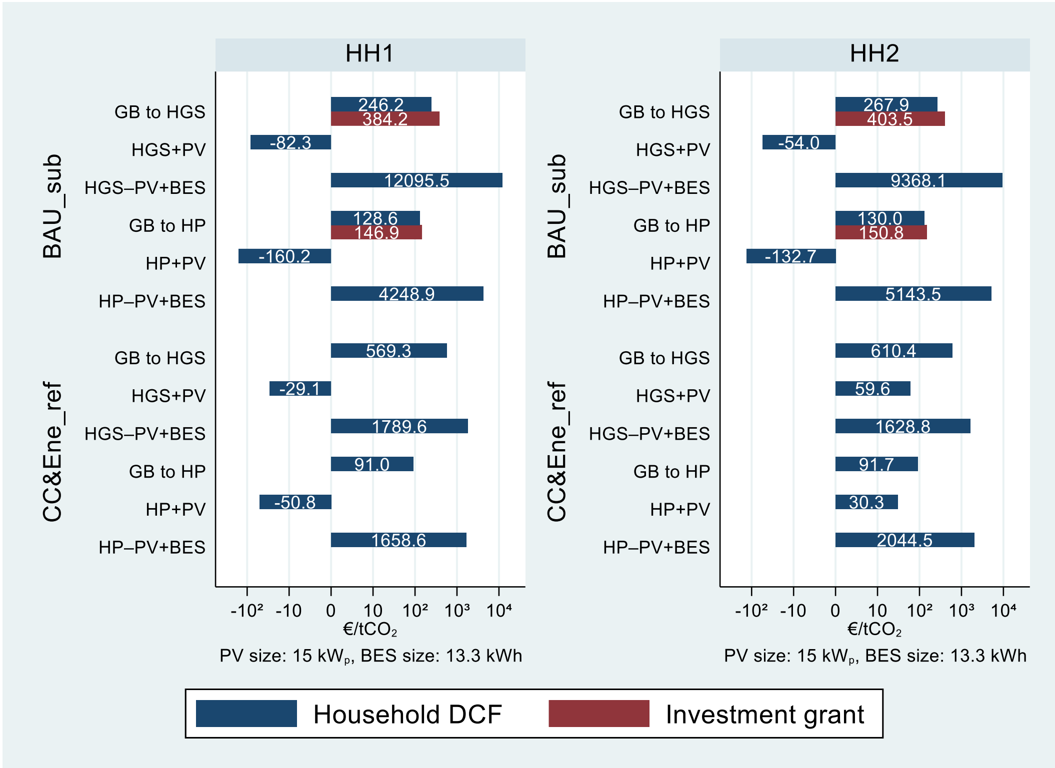


Figure 2 – Cost of avoided carbon emissions following a change of HES

Our research suggests that a more effective policy would be to shift from subsidizing technologies to penalizing CO_2 and lifting taxes and surcharges, which do not reflect carbon intensity or additional costs for the system – as represented in the *CC&Ene_ref* scenario. The cost of CO_2 emission reduction through HGS systems was far higher in both scenarios, leading to a less economically efficient decarbonization of the heating sector. The heat pump, in contrast, improved its financial attractiveness despite the removal of subsidies following the regulatory shift, thanks to the effect of reforming the regulated components of electricity prices, i.e., taxes, surcharges and network fees. Furthermore, dynamic prices led to a more favorable operation of the heat pumps, which enhanced the reduction of CO_2 emissions. As a result, for the HP, the cost of CO_2 emissions reduction was much lower in *CC&Ene_ref*. This is advantageous not only to the households, but also to the government budget because of the avoided investment subsidies. This last aspect is very relevant, as government spending for promotion schemes for decarbonizing the building sector amounted to approx. EUR 3.9 billion in 2021 [30], to approx. EUR 6.5 billion in 2022 [31] and major increases can be expected, as the planned expenditure for 2023 amounts to approx. EUR 16.9 billion [32].

Nevertheless, the best financial results from the household perspective were achieved in *BAU_sub*, in the case in which the household could save on expensive electricity through a large PV system, while benefiting from subsidies for heating systems. Therefore, *CC&Ene_ref* may not be considered strictly financially superior for every household (i.e., for prosumers), yet it is financially superior from a broader, general-welfare perspective.

Over the last year, the regulatory framework has rapidly changed in Germany in response to the spike in energy prices of 2021 and an energy crisis that were further aggravated by the Russo-Ukrainian conflict. As of 2023, subsidies for HGS energy systems were partially [10] phased out, while the surcharge to finance electricity from RETs (so-called "EEG surcharge"), which used to be part of retail electricity tariffs, was abolished. However, heat pumps are still penalized by expensive electricity prices while the energy transition in the residential sectors remains heavily reliant on subsidy schemes, and CO_2- and grid-oriented dynamic electricity prices (incl. dynamic network charges) have not been introduced.

Given the large scale of the heating transition and the push to accelerate the deployment of low-carbon heating technologies, it is vital that this is done in a way

[10] As of 2023, the investment costs associated with GBs are not subsidized anymore, whereas the part of costs for STE can still be financed by government grants.

that is economically optimal or at least not excessively expensive. Whilst this study is indicative of the problems with a regulatory framework that has already changed, the lessons on the importance of market- and carbon-oriented energy rates for retail consumers are still very valid for the German context and beyond. This study has only considered one type of building, location and two simulated households, whereas the residential sector is very heterogeneous. Considering this, the current prioritization by the German government of low-carbon heating (especially heat pumps, but also STE) by means of new subsidy schemes may not necessarily lead to a cost-efficient decarbonization. In this regard, it would be interesting to consider a wider variety of technologies, including, e.g., pellet boilers, hydrogen-ready gas boilers, biogases, as well as alternative levels of energy efficiency in buildings and building types (e.g., apartment buildings), in order to study the impact of subsidies and retail energy prices. Moreover, in contrast to this study, lifetime carbon emissions of heating technologies and of building refurbishment measures could be considered in order to obtain a more comprehensive environmental assessment. In general, there is a need for further research in this area, especially considering that the plans for the decarbonization of the heating sector have suddenly been accelerated because of the changes in the geopolitical context.

The findings have also implications regarding PV self-generation in the residential sector. Both in the status-quo scenario and in the alternative regulatory scenario (*CC&Ene_ref*), the profitability of PV self-generation relied on self-consumption potential. In the latter scenario, this occurred in spite of market-oriented power rates, i.e., lower LPOE from self-consumed electricity and high electricity prices in the wholesale market. Moreover, not only self-consumption volumes were relevant, but also coincident demand peaks. As a matter of fact, the new design of network charges may doubly penalize the adoption of PV for more energy efficient households, which are characterized by both low energy demand and low coincident demand peaks. All in all, for both households in this study, PV adoption loses, at least in part, its financial attractiveness, which is why a regulatory framework based on investment grants and high self-consumption savings might be preferable from the perspective of some households.

After the amendment to the Renewable Energy Sources Act (EEG) in 2023 [33], remuneration of electricity from renewable sources still varies depending on technologies and system sizes. For instance, the FiT for PV under 10 kW_p is set at 8.2 ct/kWh and at 7.1ct/kWh for capacities up to 40 kW_p, thereby providing incentives for less cost-efficient systems in terms of LCOE (because of economies of scales). Moreover, VAT on PV systems was also abolished, meaning that prosumers no longer face a trade-off between VAT reimbursement for investment costs and the VAT levy for self-consumed electricity.

At the same time, a new kind of “full-injection” FiT for PV operators, who exclusively inject electricity into the grid instead of self-consuming it, was also introduced (e.g., 13 ct/kWh for PV under 10 kW_p).

Such amendments to the EEG may indicate an inconsistent policy, in that, on the one hand, self-consumption is strongly incentivized regardless of the cost efficiency of electrical generation; on the other hand, small PV systems that fully export (or rather feed-in) electricity to the grid are made more profitable than larger systems with a modest level of self-consumption.

Regardless of the role self-consumption-focused PV generation, policy makers ought to set a coherent regulatory framework, in which self-consumption is either consistently favored over injection or is treated equally to electricity exports to the grid.

The assessment of the cost efficiency of self-consumption-focused, residential PV generation is beyond the scope of this paper. In other words, the question that remains to be answered is the extent to which small-scale systems, inferior in terms of LCOE, should be favored because of system-level benefits provided by reducing injection into the grid. Nevertheless, it seems reasonable to assume that such benefits should be based on the reduction of coincident injection rather than on self-consumption volumes. In this study, capacity-based charges made the coincident demand and injection peaks of PV prosumers relevant for profitability. However, even market- and grid-oriented, cost-reflective energy tariffs could not neutralize the role of self-consumption volumes, mostly because VAT and the concession fee levied on withdrawal rates rendered self-consumption still significantly more profitable than injection.

5. CONCLUSIONS

This paper has investigated how improving the cost reflectivity of energy tariffs may affect the profitability and optimal operation of alternative home energy systems. The analysis was conducted by comparing an alternative regulatory scenario consisting of two policy reforms – (i) a reform of electricity network charges where infrastructure costs are recovered through capacity charges, which include coincident demand and feed-in charges, and (ii) a carbon-oriented reform by which all energy taxes and surcharges are abolished and replaced with a uniform CO_2 pricing – to a status-quo scenario characterized by flat, volumetric energy tariffs and subsidy schemes for new heating systems. The results have shown how the proposed reforms of energy tariffs may foster a more cost-efficient energy transition in the heating sector by favoring heat pumps over hybrid gas boiler / solar thermal energy systems. In addition, the termination of the subsidy schemes would allow for considerable federal budget savings. In contrast, the status-quo policies have not been consistent with their objective, in that they have not favored an adoption and operation of technologies, leading to the largest and most cost-efficient reduction in carbon emissions.

The study has also considered the impact of such regulatory scenarios on PV self-generation, finding that, even under the proposed new regulatory regime, self-consumption potential may remain crucial for the profitability of residential distributed generation. In fact, capacity-based charges, levied both on coincident demand and coincident injection, may even exacerbate the difference in terms of PV profitability between low-energy demand and high-energy demand households. However, the recent amendments to the laws regulating small-scale PV appear also to be inconsistent, in that they entail both incentives and disincentives for self-consumption as opposed to injection. In this regard, a conclusive policy recommendation on the role of PV self-consumption cannot be provided in this paper. Nonetheless, all things considered, we see a clear need for reform which delivers a consistent regulatory framework for the residential energy sector whilst also aiming to increase the cost reflectivity of energy tariffs, both in terms of system-related and carbon-related costs. Only such a consistent, market-oriented regulatory framework may pave the way for an effective and cost-efficient decarbonization of the residential energy sector.

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