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Impact of growing national solar power capacity on the profitability of residential solar energy production in northern conditions

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ABSTRACT

This study examines the effect of increasing solar photovoltaic (PV) production on electricity market prices and analyzes how this development affects the profitability of residential PV systems. The key novelty is a comprehensive techno-economic analysis of the profitability of differently oriented residential PV systems under different electricity price scenarios. The novel approach combines PV system simulation, a large set of real electricity consumption data, and two electricity price estimation methods: linear regression and aggregated bidding curve modification. Nordic conditions with long summer days and low solar elevation angles enable the efficient use of different PV system designs, such as vertical bifacial PV, offering versatile production profiles. This study identifies how rapidly PV capacity growth cannibalizes the value of the different residential PV systems, what systems are resilient toward cannibalization, and how the national PV deployment strategy affects cannibalization in Finland. The results show that even 500 MW addition to the national PV production capacity in Finland compromises residential PV profitability in the worst-case scenario. Electricity-powered heating solutions make PV more profitable. Overall, maximizing self-consumption is crucial to maintaining the economic profitability of residential PV systems in different electricity price scenarios.

1. Introduction

Solar photovoltaic (PV) electricity generation has established its position as the most rapidly growing renewable electricity source globally [1] due to the rapid decrease in PV production costs. However, the intermittent and weather-dependent nature of PV production creates major challenges for power systems with high PV penetration. The “*duck curve*” phenomenon, the rapid ramp-up of PV generation in the morning and ramp-down in the afternoon with simultaneous and opposite changes in electricity demand, requires extensive power generation balancing. This phenomenon makes electricity prices volatile and calls for mitigation actions [2]. In a day-ahead spot price market, such as the Nord Pool market [3], the electricity clearance price is determined by a blind double -auction process in 15-min intervals since autumn 2025. This study uses 1-h time periods, which were the standard interval in 2023, the target year of the case studies. An increase in variable renewable energy (VRE), namely, PV and wind, increases the quantity of near-zero-price bids on the supply side during high VRE production periods. This increase affects the electricity price through the merit order effect: As the supply increases, the price decreases. The economic feasibility of residential PV systems depends on the electricity market price in the absence of support mechanisms.

In Germany, the European PV-forerunner, this effect occurred already in 2012–2015, when both PV and wind decreased the electricity price [4], and has continued ever since. The same phenomenon occurred in Australian states with a high share of renewables (years 2014–2019) [5], in all six Italian electricity market zones (years 2015–2019; a price decrease of €0.19–€3.0/MWh per added 100 MW of PV) [6], and in Denmark and southern Sweden with wind power (years 2016–2019) [7]. In the Dutch market (real 2020 data and 2025 scenario), increasing the PV capacity from 10 to 15 GW or 25 GW decreased the PV capture price from €44/MWh to €25/MWh or €14/MWh, respectively [8]. With current PV capacities, the electricity price can drop to zero or negative around noon [9,10]. On average, the increase in VRE generation decreased the electricity price by 0.6 % for each percentage point of VRE in the power system across 24 European countries in 2014–2021 [11].

Since VRE production is focused on certain hours, the price decrease

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Glossary

ABC	aggregated bidding curve
EE	Estonia (Nord Pool market zone)
FI	Finland (Nord Pool market zone)
H	high
HSAT	horizontal single-axis tracker
L	low
LR	linear regression
M	medium
MPV	monofacial photovoltaics
PV	photovoltaics
SE1	northern Sweden (Nord Pool market zone)
T40EW	tilt 40°, east-west orientation
T40S	tilt 40°, south-orientation
TES	thermal energy storage
VBPV	vertical bifacial photovoltaics
VRE	variable renewable energy
α, β	coefficients in linear regression model
C	electricity price (€/MWh)
CR	capture rate (%)
D	electricity demand (MWh)
P	electricity production (MWh)

during these hours is higher than the decrease in the mean price, creating the so-called cannibalization effect [12]. In interconnected electricity markets, cannibalization raises the price in net-exporting regions and lowers it in net-importing regions [13]. Cannibalization can drive PV producers to search for additional revenue from intraday markets when the price in the day-ahead market is low [14] and to prefer hybrid power plants combining PV with wind power [15]. Although the impact of PV growth on the mean market price has been widely studied, research gaps remain in using this knowledge to estimate the profitability of residential PV systems, particularly for systems with varying orientations and production profiles. The current literature lacks investigation into how small-scale PV producers can protect the value of their PV production against cannibalization and how the of national PV production profile affects cannibalization.

In certain conditions, PV can induce price-lifting effects that are higher than the price-lowering effects of PV itself. In some Australian states, the increase in PV increased expensive natural gas usage, in turn raising electricity prices [5]. Increasing PV production often raises price volatility, thereby strengthening cannibalization. In the 2010s, PV generation reduced electricity price volatility, while wind power increased it in Germany [4] and Greece [16]. In the Australian intra-day market (years 2015–2021), fixed-tilt rooftop PV with a narrow production peak increased and tracker-based utility PV with more even production throughout the day smoothened price volatility [17]. Removing thermal generation from the power system increases the frequency and severity of electricity scarcity situations when the demand is high and VRE production is low, as shown for the Finnish power system [18]. The current challenging geopolitical situation in Europe, including Russia's attack on Ukraine, further increases the risk of price peaks [19]. Considering that in 2021, 18 % of Finnish detached and semi-detached households spent over 10 % of their disposable income on energy [20], many Finns are vulnerable to energy price peaks.

We address these literature gaps by combining PV production modeling, future electricity price scenario development, and a large dataset of real electricity consumption data from southwestern Finland. Thus, we provide a comprehensive analysis of the market-based value of residential PV production in different electricity price scenarios. The expected lifetime of PV systems is 25–30 years [21], making the economic feasibility of a planned PV system subject to future electricity prices. As PV production grows rapidly, there is an urgent need for knowledge about the residential PV production value that we create with this work, especially for small-scale producers, such as individual houseowners. Large companies typically make power purchase agreements in advance for their production. By contrast, individuals have limited options for selling PV electricity and generally lack the capability to perform lifetime net present value calculations at the same level as large companies. We address this gap by connecting electricity price scenarios to market-based residential PV electricity value.

In Finland, PV is a small (1.4 % of the total electricity consumption in 2024 [22]) but rapidly growing electricity source. By June 2025, the total aggregated capacity of the published utility-scale PV power plant projects in the planning or permitting stage exceeded 26 GW [23]. For comparison, the mean electricity consumption during the summer around noon in Finland is around 8 GW [24]. If even a fraction of the planned PV plants will be financed, built, and commissioned, PV will become a major factor affecting the electricity market price, similar to the role that wind power plays today; however, estimations of the impacts of this change are lacking from the literature. In Sweden, large PV plants can achieve profitability with historical spot prices, but future price development creates uncertainties [25]. Fingrid, Finland's transmission system operator, estimates that the annual PV production will be 10 TWh in 2030 and 16 TWh in 2035 [26]. These numbers require that approximately one-third of the current planned utility-scale PV power plants will be built by 2030 and more than half by 2035. This development compromises the profitability of residential and utility-scale PV systems alike, creating the need to study what PV systems are most resilient to future uncertainties for Finnish residential consumers.

Our work expands the analysis of VRE's impact on the electricity price and its volatility to the Finnish context. We adapt two electricity price models, quantile regression [9] and aggregated bidding curve (ABC) modification [10], to the Finnish context. The regression model identifies the key predictors affecting electricity price, namely, VRE, nuclear power production, and electricity load in the Finnish context, and fits the model to real data. Natural gas, an important price-maker in many European countries, is negligible in Finland; in 2021, natural gas was the marginal fuel defining the market clearance price for only 3 % of the time, whereas in Europe (EU27 + Great Britain + Norway), the corresponding number was 39 % [27]. Therefore, predicting electricity prices based on natural gas prices and usage is infeasible in Finland. Instead, this work uses the bidding curve modification method, which adds additional PV production to the day-ahead market auction's supply curve, to include the dynamic electricity market effects in the methodology. Our previous work [28] adapted the principle from Ref. [9] to Finnish conditions, whereas another study estimated the electricity price in Finland in 2030 by predicting the average supply curve [29].

As PV changes the electricity price dynamics, the markets adapt. Price-aware consumers adjust their consumption based on price signals, creating natural demand elasticity, as shown in Denmark [30]. On the supply side, tailoring the PV production profile to match the electricity market price is beneficial in power systems with high PV production [31]. The market signal can discourage PV investments, even by one-third reduction according to a Swedish study [32]. The large-scale integration of east-west mounted vertical bifacial PV (VBPV) in Europe shifts production from noon to morning and evening, increasing the value of PV production and decreasing the base-load electricity price [33]. These observations show that VBPV is a feasible option across Europe due to the production shift, although the benefits compared with south-facing PV are the highest in northern Europe [34]. Thus, our work on VBPV also has wide application potential outside the Nordic countries.

Energy storage and load shifting can contribute to increasing self-consumption on a residential scale. The high heat demand in the Nordic countries makes thermal energy storage (TES) feasible. A high school in Norway increased the self-consumption rate of a 235 kW PV system from 48 % to 74 % with TES [35]. In Finland, optimized hot water heating of a residential house increased the internal rate of return of a PV system by 0.6 percentage points [36]. However, energy storage creates additional costs, whereas load shifting may compromise resident's comfort.

In Finland and elsewhere in the Nordic Countries, unique solar conditions make some innovative solutions, such as VBPV, especially suitable [34]. The low solar elevation makes façade-mounted PV systems appropriate for unshaded locations [37]. The optimal PV system for each producer varies; a Finnish study optimized the size and orientation of a PV system for a grocery store (89 kW, south), a dairy farm (28 kW, east-west), and a residential house (5.2 kW, south) [38]. For a Finnish residential PV producer, maximizing the self-consumption of the produced PV electricity is critical for economic profitability [39] due to the formation of residential electricity prices. In the absence of feed-in tariffs, the only compensation that residential PV-producers receive for the electricity fed to the grid is the tax-free spot price. For self-consumed PV, however, the residential producer saves the cost of electricity, transmission fees, and taxes. In 2023, electrical energy formed only 45 % of the total electricity purchase costs for a detached house with 5–15 MWh annual consumption [40], highlighting the importance of self-consumption. However, the existing literature lacks estimations of the lifetime profitability of residential PV systems in Finland under different electricity pricing scenarios.

Our work combines local-level analyses of residential PV production and electricity consumption, with national-level electricity price development scenarios to define the economic profitability of residential PV in Finland. Compared with our previous study [39] and other study [41], the electricity price scenarios based on the price formation mechanics in the Nord Pool [3] day-ahead market in Finland and a large set of real residential electricity load profiles form the key novelty. We quantify VRE-induced price reduction and estimate the effect of increasing PV production on future electricity price. We create hourly electricity price profiles with five national PV deployment strategies and calculate the economic value of residential PV production, quantifying the residential PV electricity value cannibalization. The impact of the national PV production profile on residential PV system owners is lacking in the literature, a gap we address in this work. We study three residential PV system orientations and identify the PV systems that are the most profitable and resilient in different electricity price scenarios. Outside academia, our work is valuable for individuals who are considering investing in PV and for national decision makers who aim to advance PV deployment.

This work answers the following research questions:

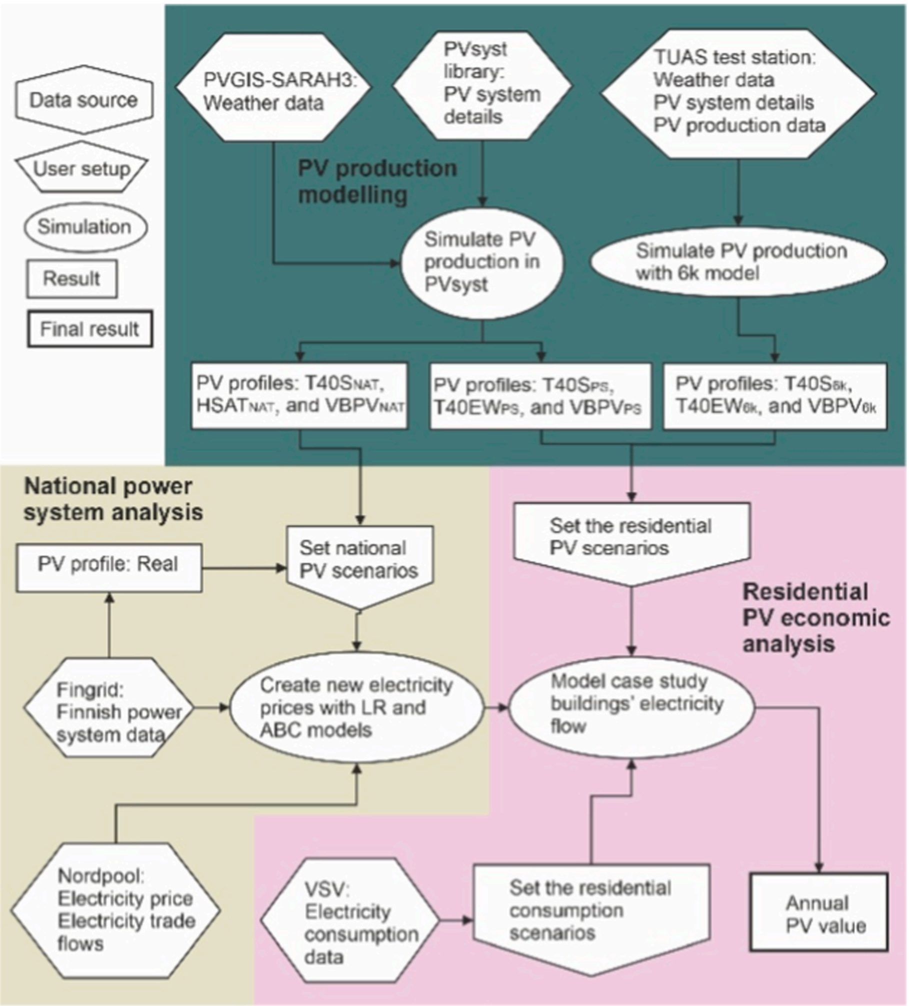

Fig. 1. The workflow of this work, from raw data sources to the final results. The workflow is divided into three sections: PV production modeling, national power system analysis, and residential PV economic modeling.

1) How rapidly the value of the production of different PV system orientations in residential setting decrease in Finland if no other mitigation actions (e.g., load shifting) are taken?
2) How does the transfer from small-to utility-scale PV systems in national PV production affect the profitability of residential PV installations?
3) What are the key factors enabling profitable and resilient PV production in different electricity price development scenarios?

2. Methodology

2.1. Workflow

The workflow of our methodology is presented in Fig. 1. The flowchart shows the chain from the raw data sources to the final target variable, the annual value of the produced PV electricity. Detailed descriptions of each step in the flowchart are presented later in this section.

2.2. Methods for estimating future electricity price

2.2.1. Linear regression model

The linear regression (LR) model with 11 predictors was fitted to real Finnish power system data from 2023, expanding the methodology from our previous work [28]. This approach provides electricity price estimates that resemble the average price, which is suitable for annual analysis, although it is incapable of capturing extremely high and low prices. Adding PV to the power system causes a decrease in the hourly electricity price during PV production hours. The equation of the model is shown in Eq. (1):

$$C_t = \alpha + \beta_1 X_{1,t} + \ldots + \beta_{11} X_{11,t}, \tag{1}$$

where C_t is the electricity price for hour t, α is a constant, and $\beta_1, \ldots, \beta_{11}$ are the coefficients corresponding to the predictors $X_1, \ldots, X_{11}$. The predictors used are shown in Table 1. The price data are from Nordpool [3], and other electricity market data are from Fingrid [24]. The fitting is done in the Python SciPy-library with the lsq_linear -function.

Predictors 1–3 represent the key variables in the Finnish electricity market: demand, VRE production, and nuclear power production. Natural gas, which is an important price predictor in many European countries, is excluded, since its role in electricity price formation and electricity supply in Finland is minimal [27]. Predictors 4 and 5, EE_{RISE}, and $SE1_{LOW}$ represent the impact of electricity trade. EE_{RISE} is set to 1 when the electricity is more expensive in Estonia than in Finland and the electricity export from Estonia to Finland could increase. Similarly, $SE1_{LOW}$ is set to 1 when electricity is more expensive in Finland than in northern Sweden and the import to Finland could increase. The justification for these electricity trade predictors is shown in the Supplementary Information, Section S1. Predictors 6–11 identify the impact of holidays, season, and the time of the day on the electricity price.

The model is fitted separately for different segments of the base year (2023) to account for price behavior during different PV production conditions (Table 2 and Table S1). The data are segmented based on the relative PV production (limit: 5 % of the aggregated nominal capacity) and the absolute aggregated VRE production (limits: percentiles 25, 50, and 75 of the real 2023 values). The absolute value limits for the categories (as MWh/h of VRE production) are kept as constants for all simulated scenarios. Thus, some hourly data points move from one category to another. The LR-fit price profile had a slightly lower annual mean value (€55.6/MWh) than the actual price (€56.5/MWh), whereas the parameter R^2, describing the goodness of the fit, was 0.501. The low R^2 value results from the fit's inability to capture extremely high and low prices. For the monthly average curves, the R^2 value was 0.779 for the electricity price and 0.938 for the PV market value. Thus, despite its limitations, the LR-model can capture the expected PV value at a monthly resolution.

Table 1
Predictors for estimating the electricity price.

X	Predictor	Unit	Description
1	D	MWh/h	Electricity consumption
2	P_{VRE}	MWh/h	Aggregated VRE production
3	P_{NUC}	MWh/h	Nuclear power production
4	EE_{RISE}	–	1 if EstLink criteria are triggered, 0 otherwise
5	$SE1_{LOW}$		1 if SE1criteria are triggered, 0 otherwise
6	Holiday	–	1 if holiday, 0 otherwise
7	Summer	–	1 for May–Aug, 0 otherwise
8	Winter	–	1 for Nov–Feb, 0 otherwise
9	Morning	–	1 for hours 7–10, 0 otherwise
10	Daytime	–	1 for hours 10–17, 0 otherwise
11	Evening	–	1 for hours 17–21, 0 otherwise

The increase in PV production is modeled by increasing the value of predictor 2 (P_{VRE}), which decreases the electricity price according to the factor β_2. The impact of PV on electricity price is the highest in category 2.1 (day, low wind) and the lowest in category 2.4 (day, high wind). These observations result from the negative correlation between wind power production and electricity prices. Thus, in low-wind-high-price conditions, there is more room for PV-induced price decreases than in high-wind-low-price conditions.

2.2.2. Aggregated bidding curve model

In Nord Pool's day-ahead auction, the electricity price is defined for each hour from the intersection of supply and demand bids. The demand and supply curves are step functions in descending order for the demand curve and increasing order for the supply curve. The implemented algorithm iteratively searches for the intersecting bids to define the price. If the intersecting bids are vertical, the clearing price is the start price of the intersecting supply bid, which is the lowest acceptable price for all bids.

The ABC model implements the additional PV production as a supply bid that has a price of €0/MWh. The start quantity is defined as a point directly after the bid with the largest end quantity and price at a maximum €0/MWh. All quantities of the existing bids with prices higher than €0/MWh are increased by the quantity of the new bid. This procedure creates a new bid curve and defines the new price. Fig. 2 illustrates how adding 2 GW of PV production shifts the supply curve to the right by 2 GW for positive prices, decreasing the clearing price by €15/MWh.

The ABC model has limitations. The impact of PV production increase on the net import between Finland and neighboring market zones is excluded, which creates inaccuracies with high added PV production. When the price in the Finnish bidding zone is the same as that in the neighboring zones, the neighboring bidding zones without congested interconnections may have different clearing prices from the supply-demand curves. In this situation, the price in all these bidding zones is the highest clearing price among the zones, which may result in the

Table 2
Distinct categories and key parameters. The column 'n' stands for the number of datapoints and β_2 is the coefficient for the parameter P_{VRE}.

Category	Typical occurrence	PV < 5 %	VRE quarter	VRE lower limit (MWh/h)	Sample size	β_2 (10^{-2})
1	Night and winter	Yes	Any	N/A	5401	−2.131
2.1	Day, low wind	No	First	0	922	−8.254
2.2	Day, some wind	No	Second	701	1043	−4.183
2.3	Day, medium wind	No	Third	1394	841	−2.699
2.4	Day, high wind	No	Fourth	2524	553	−1.830

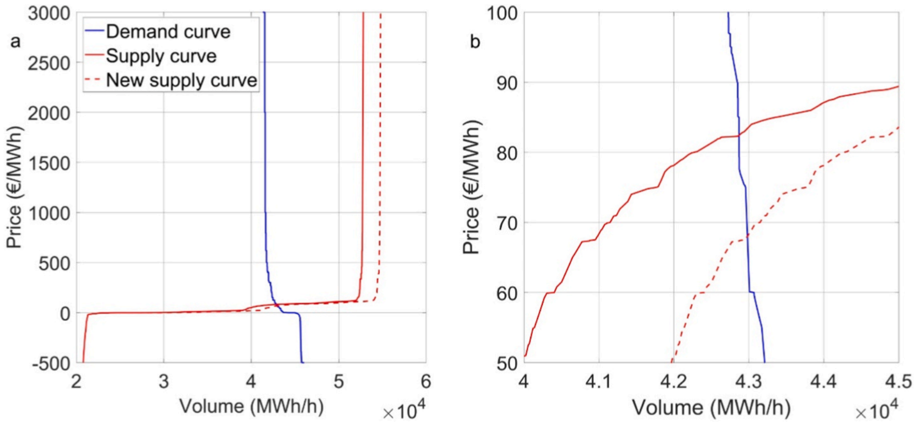

Fig. 2. Impact of an additional 2 GW of solar power on electricity price. Subfigure "b" is a zoom-in of subfigure "a" close to the clearing price. The figure is based on Nord Pool's data [3].

Finnish clearing price differing from the price in the Finnish bidding zone. Validation with year 2023 data without PV additions showed that this limitation led to an underestimation of €0.008/MWh on average and to a price deviation of at least €2/MWh for 2.1 % of the hours. Thus, its impact on the results is marginal.

2.3. Analyzed scenarios for electricity price development

Business-as-usual. The national PV production profile, normalized with capacity, remains constant (the year 2023 profile based on Fingrid Open Data [24]). The profile consists mainly of rooftop installations, favoring the south orientation, with constraints resulting from the building orientation and the roof tilt angle. This is a reference scenario, noted as *Real*.

Alternative PV orientations. The production profiles for differently oriented bifacial PV systems are created using commercial software (PVsyst [42]) in five locations. These locations represent the largest PV power plant under construction (Kalanti, 206 MW, 60.82°N, 21.58°E) and the four largest PV power plants under planning as of October 2024: Suursuo and Huuhaansuo (600 MW, 60.98°N, 27.95°E), Aurinkonevat (500 MW, 62.30°N, 22.38°E), Huittinen (475 MW, 61.15°N, 22.60°E), and Ulvila (430 MW, 61.49°N, 21.98°E). The profiles included are described in Table 3.

The national profiles used are linear combinations of the single-orientation profiles and the *Real* profile (Table 4). The *Conventional* profile considers the trend to move to utility-scale installations, *Dual-use* is an extreme case in which most of the added PV will be added as VBPV, *Balanced* has equal contributions of all four profiles, and *Utility* focuses on the $HSAT_{nat}$ option. The profiles are visualized for a sunny summer day (June 10, 2023) in Fig. 3. The real 2023 PV production profile is used as a baseline for all scenarios. For each of the five PV development scenarios (*Real*, *Conventional*, *Dual-use*, *Balanced*, and *Utility*) 100–2000 MW of PV capacity with 100 MW intervals is added to the baseline.

Table 3
Descriptions of the PV orientations used to create the national PV scenarios.

Profile	Description	Characteristics	Output profile description
$T40S_{nat}$	Fixed 40° tilt, south-facing, 8 m row spacing	Fixed orientation suitable for Finnish conditions, requires minimal maintenance	High and narrow peak around noon
$HSAT_{nat}$	Horizontal single-axis tracker in the north-south direction, 8 m row spacing	Utility-scale PV facility with high production in the morning and evening, and higher maintenance need	Remains relatively constant throughout the day
$VBPV_{nat}$	Vertical bifacial PV, facing east and west, 30 m row spacing	Suitable for applications focusing on the dual-use of land (e.g., agrivoltaics)	Production peaks in the morning and evening, with a valley around noon

Table 4
Components, their shares, and the total annual electricity production for the five PV scenarios used in this study.

Profile	*Real* (%)	$T40S_{nat}$ (%)	$HSAT_{nat}$ (%)	$VBPV_{nat}$ (%)	Annual production (MWh/MW)
Real	100	0	0	0	1080
Conventional	40	30	30	0	1170
Dual-use	10	10	20	60	1120
Balanced	25	25	25	25	1150
Utility	0	20	60	20	1220

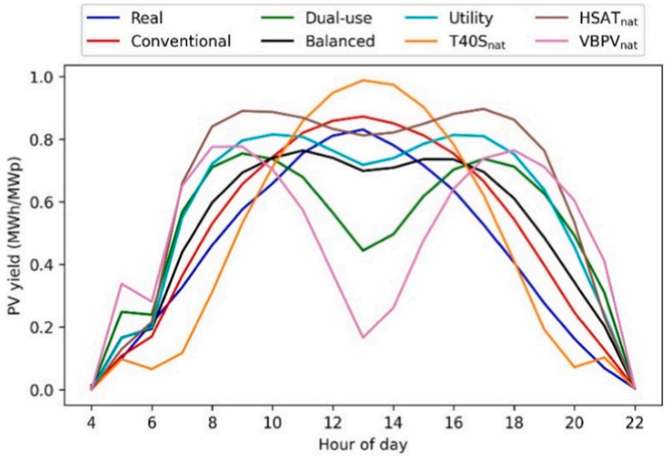

Fig. 3. PV profiles used in this work for a sunny summer day.

2.4. PV system electricity value for residential PV

2.4.1. PV system modeling

The power productions of differently oriented and sized residential PV systems were modeled using two approaches:

1) The 6k model [43] applied in our previous framework [39] and found suitable for the conditions in Turku, Finland [44] with parametrization done based on a real, south-facing PV system

located in Turku, Finland [45] (weather data acquired from Ref. [46])

2) The commercial software, PVsyst [42] with PVGIS SARAH-3 -derived weather data [47] and Generic Mono 500 Wp Twin half-cells bifacial solar panels from the PVsyst library.

Subscripts 6k and PS are used to distinguish these methods. The orientations area a roof-mounted and south-facing system with 40° tilt angle (T40S), a roof-mounted east- and west-facing system (1:1 ratio) with 40° tilt angle (T40EW), and a vertical bifacial system (VBPV). The reference system size is 4 kW, which is realistic for a rooftop installation (or, for VBPV, a backyard fence). The total annual productions of these systems were 3750 kWh, 3040 kWh, and 4560 kWh for $T40S_{6k}$, $T40EW_{6k}$, and $VBPV_{6k}$, respectively. For the $T40S_{PS}$, $T40EW_{PS}$, and $VBPV_{PS}$ systems, the values were 4430, 3320, and 4490 kWh. In PVsyst simulations, PV systems were in shading-free locations. Smaller (2 kW) and larger (6 kW) systems were simulated for system size sensitivity analysis. PV production was used at the spot (self-consumption), if possible.

2.4.2. Electricity consumption profiles

Real anonymous electricity consumption data (hourly resolution) from individual end users in southwestern Finland for the year 2023, provided by Vakka-Suomen Voima (VSV), are used. Three detached house types with different heating methods are analyzed: NoElHeat (no electric heating), DirElHeat (direct electric heating), and AdvElHeat (advanced electric heating, i.e., a heat pump). For each house type, medium (M) electricity consumption forms a base case, whereas low (L) and high (H) consumption cases are used for load sensitivity analysis (Table 5). The method for identifying the suitable consumption profiles for each house type is explained in detail in the Supplementary Information, Section S2.

2.4.3. Annual value of the produced PV electricity

The value of PV electricity is defined as the savings on the electricity bill for self-consumed production and as the revenue when sold to the grid for the surplus production. The formula is shown in Eq. (2), with a detailed explanation in Ref. [39]:

$$VAL_{PV} = \sum_{i=1}^{8760} \left(E_{SC,i} \cdot C_{purchase,i} + E_{sur,i} \cdot C_{sell,i} \right) \tag{2}$$

where $E_{SC,i}$ and $E_{sur,i}$ are the self-consumed and surplus PV production (kWh), respectively, $C_{purchase,i}$ is the total cost of buying electricity, and $C_{sell,i}$ is the revenue for selling PV electricity during hour i.

For the savings, the consumer is expected to have a spot price contract. The electricity price consists of the Nordpool spot price, a margin (0.40 c/kWh), and value-added tax, which is 10 % for January to April and 24 % for May to December, applied only for positive prices. Real electricity transfer fee (Turku, Finland) and electricity tax (Finland) for the year 2023 are used. In total, the transfer fee and electricity tax form a constant 6.22 c/kWh cost. For selling electricity, we use the tax-free spot price minus margin contract, which is typically the only available option for a Finnish small-scale PV producer. Each house is simulated with a 1-h resolution for a full year to capture the total annual value of the generated PV electricity. For all house types, the value is calculated individually for each end-user consumption profile. These values are then averaged to obtain the final result. Since the aim of this study is to map the market-based value of residential PV production, and Finland lacks feed-in tariffs for residential PV, we exclude the impact of PV remuneration from this work.

Table 5
Annual electricity consumption and sample size for different house types. The economic simulation is done for each house separately, and the result shown is the average of individual values.

House type	Annual consumption (kWh)	Sample size
NoElHeat-L	3000 ± 200	159
NoElHeat-M	5000 ± 200	101
NoElHeat-H	7000 ± 200	53
DirElHeat-L	15,000 ± 600	135
DirElHeat-M	20,000 ± 600	38
DirElHeat-H	25,000 ± 600	16
AdvElHeat-L	10,000 ± 400	23
AdvElHeat-M	12,000 ± 400	22
AdvElHeat-H	14,000 ± 400	13

Capture rate (CR) is used to evaluate how well a power plant's generation captures the market price of the electricity. In some studies, the term ”value factor” is used as a synonym for CR. The formula of CR is shown in Eq. (3):

$$CR = \frac{\sum_{t=1}^{8760} (E_t \cdot C_t)}{\sum_{t=1}^{8760} (E_t) \cdot \overline{C}}, \tag{3}$$

where E_t is the electricity generation, C_t is the electricity price during hour t, and $\overline{C}$ is the mean electricity price during the analysis period (here one year). In brief, CR shows the fraction of the mean value of the power plant's energy generation in the spot market and the annual mean electricity spot price. A CR lower than one means that the electricity generation focuses on low-price hours.

3. Results and discussion

3.1. Electricity mean price and PV capture rates

Our approach adds PV production to the system while keeping other factors constant, decreasing the electricity price. Fig. 4 shows the mean electricity price development in different scenarios for both LR and ABC models. The tax-free mean electricity spot price in the Nord Pool day-ahead market for the FI market zone in 2023 was €56.5/MWh, whereas PV production in 2023 was 828 GWh. For each scenario, the new electricity mean price (€/MWh) is calculated and plotted as a function of the added annual PV production compared with the base case (GWh). Adding 100 MW of PV capacity increases annual production by 108–122 GWh, depending on the national profile (Table 4).

The LR model shows a linear price decrease. The slope of the line is €-3.0/MWh per added 1000 GWh of PV production, quantifying the effect of PV production increase on the electricity mean price when other factors remain constant. The ABC model shows a rapid price drop, especially with small added capacity; the price drop for the first added 100 MW of PV production is already €2.5–2.6/MWh. This phenomenon likely results from the limitations discussed in Section 2.2.2 and the blind double auction principle of the Nord Pool market: The actors plan their bidding strategies based on the current capacities. Therefore, recalculating the electricity price with additional PV production excludes the effect that the capacity increase has on the bidding strategies. These limitations seem to overestimate the electricity price drop with small capacity increases, especially with the first 500 MW added.

The mean electricity price is strongly affected by winter prices, which have only a marginal impact on PV in Finnish conditions. To analyze the spot price during high PV generation times, the daily average price profile from spring to summer (April 1, 2023–August 31, 2023) is shown in Fig. 5. For simplicity, the values are shown for 1000 MW and 2000 MW added PV capacities. All PV deployment scenarios show a large drop in electricity price from the morning to the afternoon. In the evening, the price drops are much smaller. The *Dual-use* profile showed minor resilience considering noon prices, but the price drop from the real 2023 values remains high. The *Real* and *Conventional* profiles were the most vulnerable to the price drop.

Fig. 6 and the Supplementary Information, Section S3 (Tables S2 and

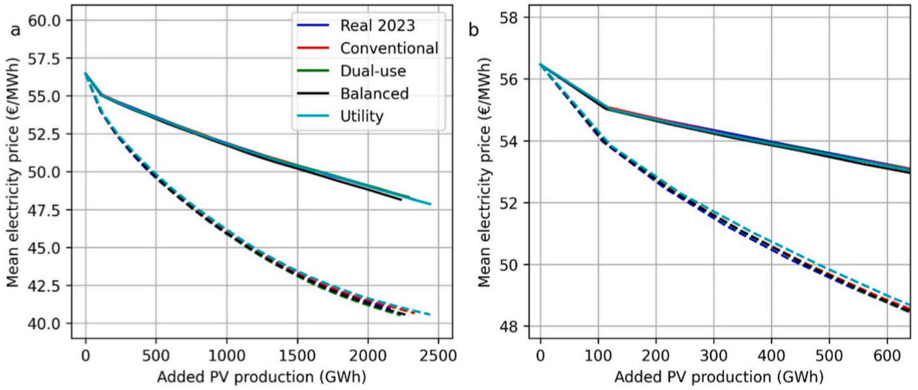

Fig. 4. Mean tax-free electricity spot prices in the different studied scenarios. The solid lines represent linear regression, and dashed lines represent aggregated bidding curve price modelling methods. Subplot (b) is a zoom-in of subplot (a). The x-axis variable is the added annual PV production in each scenario: x = 0 GWh is the real year 2023 case, where PV production is 828 GWh.

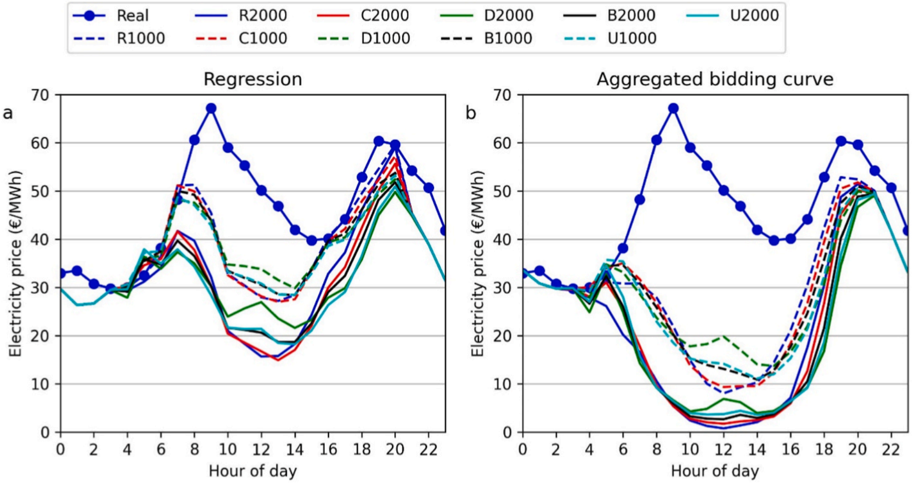

Fig. 5. Mean electricity spot price vs. hour of day for the period April 1, 2023–August 31, 2023 with the Real (R), Conventional (C), Dual-use (D), Balanced (B), and Utility (U) national PV deployment scenarios. The solid lines represent 2000 MW and the dashed lines represent 1000 MW capacity additions. The blue line with circle markers is the real 2023 spot price. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

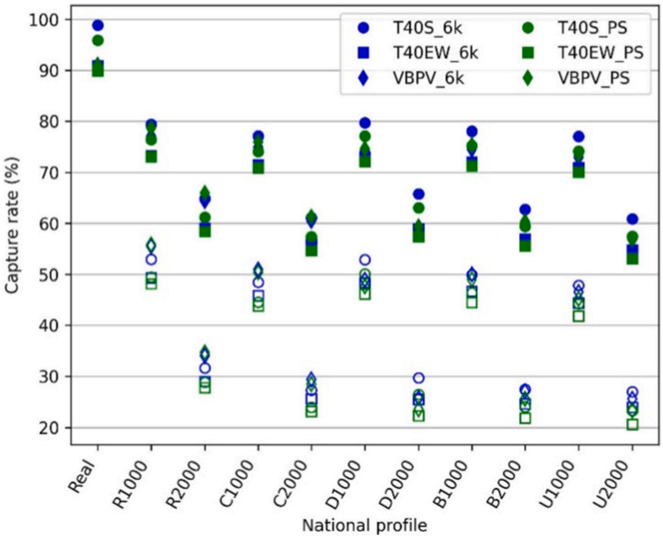

Fig. 6. Capture rates of residential PV profiles with the Real (R), Conventional (C), Dual-use (D), Balanced (B), and Utility (U) national PV deployment scenarios. Filled markers represent the LR and hollow markers represent the ABC model.

S3) show the *CR*s of the residential PV profiles in different electricity price scenarios. For simplicity, only the added PV capacities of 1000 and 2000 MW are shown. The drops in *CR*s are faster than the mean electricity price decrease, since the price decrease primarily affects hours of high PV production. With the real 2023 electricity prices, the *CR* range was 90 %–99 %, whereas with the ABC model and 2000 MW capacity addition, the *CR* can drop as low as 21 %.

3.2. Residential PV production value for the reference system

We simulated a 4 kW PV system with medium-load households to establish the base scenarios. The development of PV value in the different national PV scenarios is shown in Fig. 7 for 6k-modeled PV production and in Fig. 8 for PVsyst-modeled PV production. Subplots a–c show the results obtained with the LR, and subplots d–f show the results obtained with the ABC electricity price model. For comparison, our previous work calculated €81.5/kW as the threshold value to cover the initial investment costs of the 4 kW system, assuming €1.25/Wp investment cost, a 30-year lifetime, and a discount rate of 5 % [28]. This value is represented by the black dashed line in Figs. 7 and 8. To achieve profitability, the PV value must exceed the investment cost threshold with a margin that covers reasonable operating costs. To improve readability, we show data for national PV capacity additions of 500, 1, 000, 1,500, and 2000 MW. PV production values calculated with the real

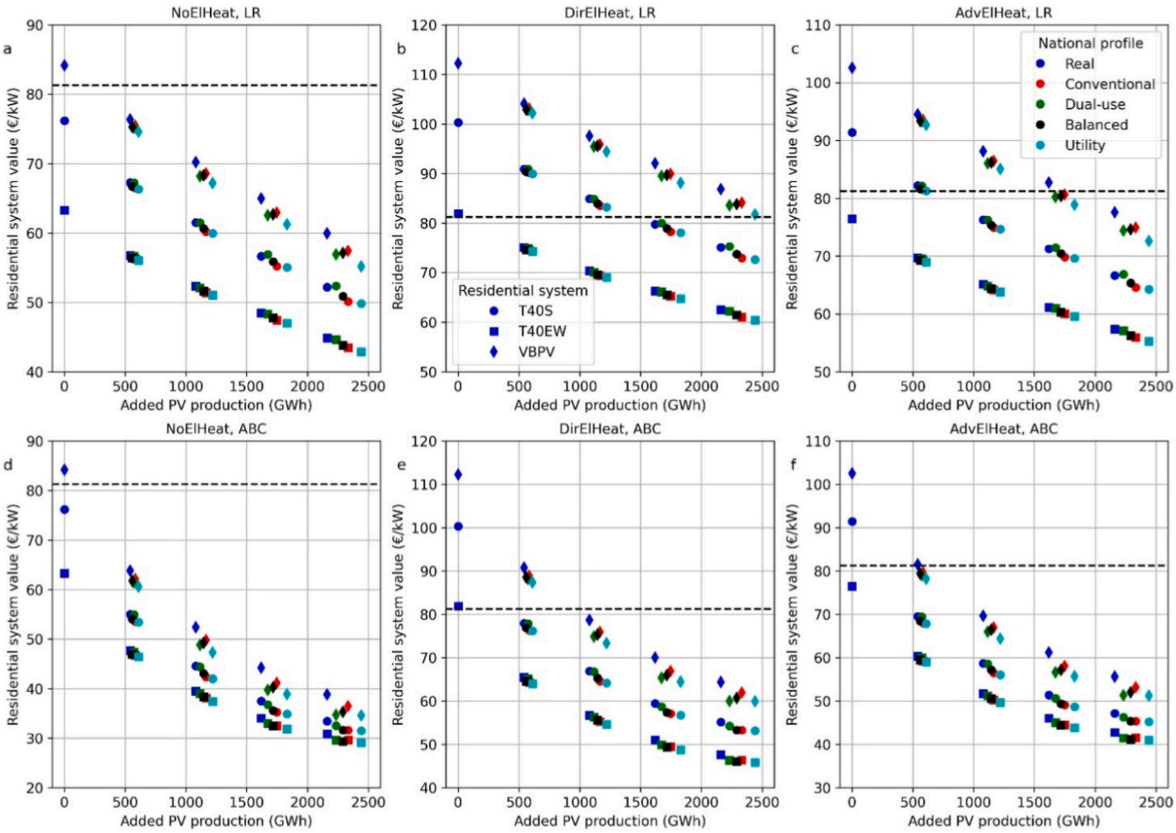

Fig. 7. Residential PV (6k) electricity value development in different scenarios (a–c for LR and d–f for ABC price models) for residential class NoElHeat-M (a and d), DirElHeat-M (b and e) and AdvElHeat-M (c and f). The x-axis variable is the added annual PV production in each scenario: x = 0 GWh is the real year 2023 case, where PV production is 828 GWh. The black dashed line (at 81.5 €/kW) indicates the annual value that covers the investment costs.

2023 data varied from €63.3/kW (NoElHeat-M, $T40EW_{6k}$) to €112/kW (DirElHeat-M, $VBPV_{6k}$). For comparison, the annual electricity bills without any PV system were €712, €2,900, and €1690 for NoElHeat-M, DirElHeat-M, and AdvElHeat-M, respectively (shown in Supplementary Information, Section S4).

For the NoElHeat-M load profile, PV was unprofitable, even with the real 2023 prices for most systems. With electric heating, VBPV had annual production values exceeding the profitability threshold, even with small increases in national PV capacity. The factors accounting for the variations in the results are the differences in the total annual production and in the self-consumption for the studied PV system–Electricity load combinations. For example, with PV profile $T40S_{6k}$, the self-consumption rate was 36.4 % with the load NoElHeat-M and 68.5 % for the load DirElHeat-M, leading to production values of €76.2/kW and €100/kW (real 2023 electricity prices), respectively. The self-consumption rates are analyzed in more detail in Section 3.3.

The LR-model shows a nearly linear decrease in the electricity value as a function of added national PV capacity when the other parameters are kept constant. The slopes of the lines are primarily determined by PV orientation, while the heating and PV modeling methods have only minor impacts. For every added TWh of national PV production, the annual value of 4 kW residential PV system production decreased by €36–38, €29–30, and €42–44 for T40S, T40EW, and VBPV, respectively, using 6k-profiles. With PS-profiles, the corresponding values were €43–45, €32–34, and €42–44, respectively. The differences between the orientations result from the initial production values of the systems; systems with higher initial values experience greater absolute value losses.

The ABC model shows a steep price drop, especially for the first 500 MW capacity increase, due to the model's sensitivity to small capacity increases (Section 3.1). Beyond the choice of price estimation models, the orientation of the PV system and the total national PV production are the dominant factors affecting profitability. With the *Real* profile, residential VBPV is attractive, whereas with the *Utility* national profile, T40S residential profiles retain their values better than VBPV. However, the cannibalization of the PV production value is high in all cases.

The most notable difference between the 6k and PS profiles was the higher production of $T40S_{PS}$ compared with $T40S_{6k}$. The difference is a result of the reduced production of $T40_{6k}$ close to noon during sunny summer days. The likely explanation for this phenomenon is the assumption of an unshaded location with the simulations done using PVsyst. Thus, PVsyst-simulations represent ideal cases for T40S and T40EW systems, whereas 6k-modeled production represents more realistic conditions by including shading from surroundings and inverter clipping. For VBPV, however, PVsyst-simulations gave lower production (and value) than 6k modeling, highlighting the challenges of modeling this configuration. However, the key conclusions considering the electricity price development with these two different modeling methods hold.

3.3. Sensitivity regarding the system and house consumption size

Variations in house consumption affect the self-consumption rate and, consequently, the economic value of the PV electricity produced. When the PV system size is increased, the share of self-consumption of the added production is smaller than the share of self-consumption of the existing production, which leads to a lower value per produced kWh. To study the sensitivity of our reference case to variations in PV system size and house electricity consumption, the simulations presented in Section 3.2 are repeated for 4 kW PV systems with lower and higher loads (Table 5) and for smaller (2 kW) and larger (6 kW) PV systems with medium loads.

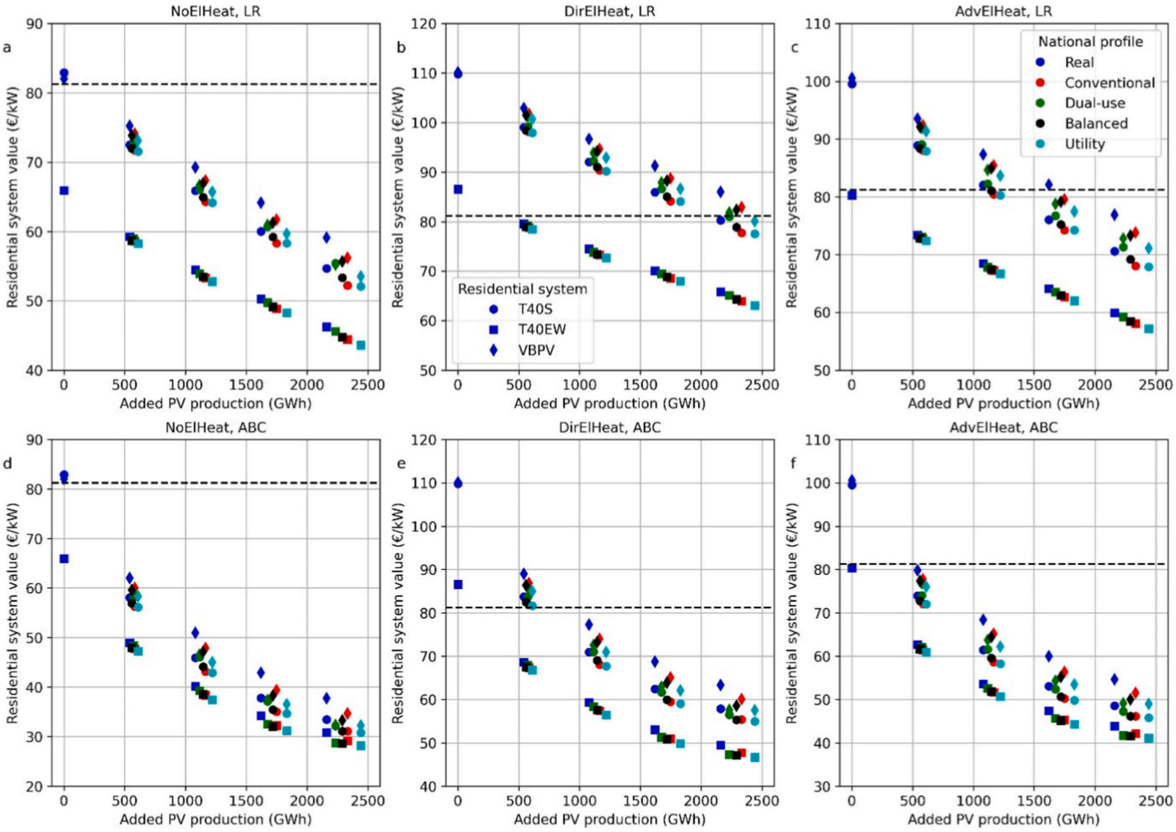

Fig. 8. Residential PV (PVsyst) electricity value development in different scenarios (a–c for LR and d–f for the ABC price models) for residential class NoElHeat-M (a and d), DirElHeat-M (b and e) and AdvElHeat-M (c and f). The x-axis variable is the added annual PV production in each scenario: x = 0 GWh is the real year 2023 case, where PV production is 828 GWh. The black dashed line (at 81.5 €/kW) indicates the annual value that covers the investment costs.

The results for the lower and higher loads are shown in Fig. 9 for 6k-

modeled PV production. In each subplot, the generated value with the

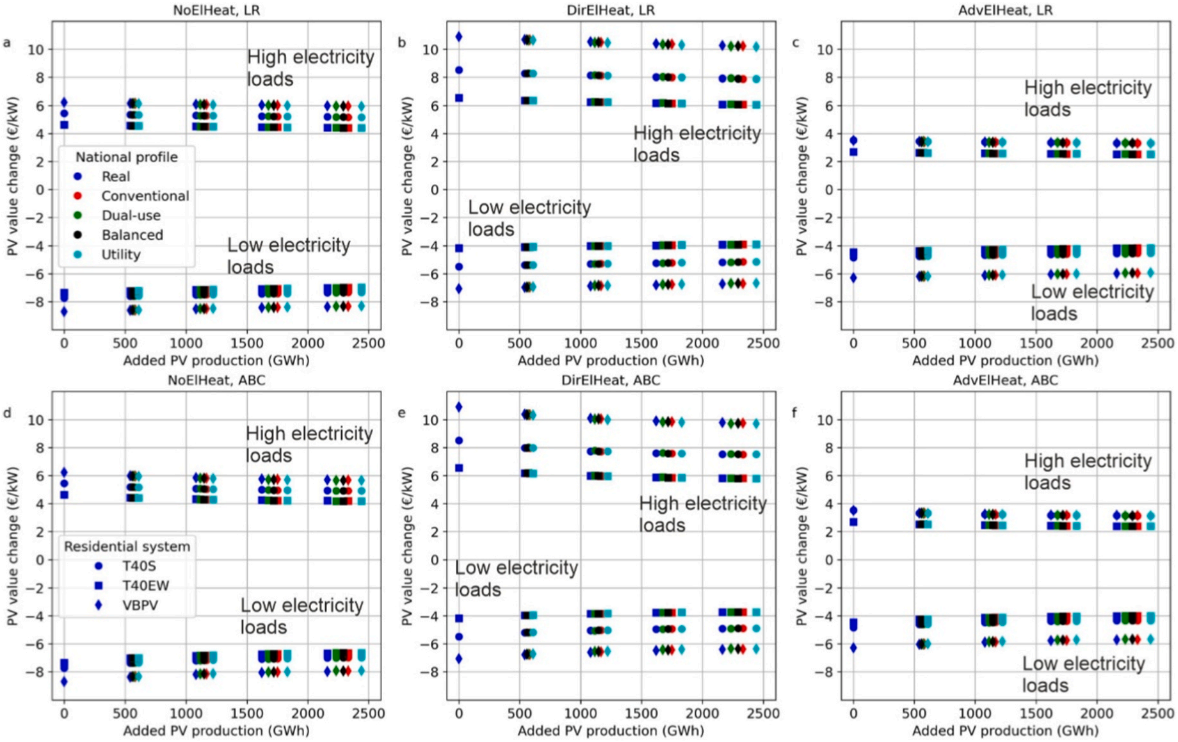

Fig. 9. Residential PV (subplots a–c for LR and d–f for ABC) electricity value changes in different load sensitivity scenarios for residential class NoElHeat (a and d), DirElHeat (b and e) and AdvElHeat (c and f).

alternative ("L" and "H") load cases is compared with the medium ("M") load case for the same house type (Table 5). The data show interesting trends. First, the changes (both positive and negative) are highest with VBPV. The largest negative changes were observed in NoElHeat houses and the largest positive changes in DirElHeat-houses, whereas AdvElHeat-houses experienced only small changes. These observations may result from changes in self-consumption rates. The differences between LR (Fig. 9a–c) and ABC (Fig. 9d–f) price models were minor.

The effect of PV system size variations (±50 %) is shown in Fig. 10. When the PV system size is increased, the value per kW decreases due to decreased self-consumption, and vice versa, when the PV system size is decreased. The absolute changes are higher when the system size is decreased. The value changes are explained by the impact of PV system size on the self-consumption rates for PV–house combinations (Fig. 11). As self-consumption rate increases (2 kW systems), the value per kW increases, whereas increasing the system size from 4 kW to 6 kW decreases self-consumption rate (and value per kW), since a higher share of the produced electricity is sold to the grid. However, since the investment costs per kW are lower with larger systems, the decreased value per kW may still be acceptable. The changes are slightly reduced as the national PV capacity increases. Overall, the differences between the LR (Fig. 10a–c) and ABC (Fig. 10d–f) electricity price estimation models were small.

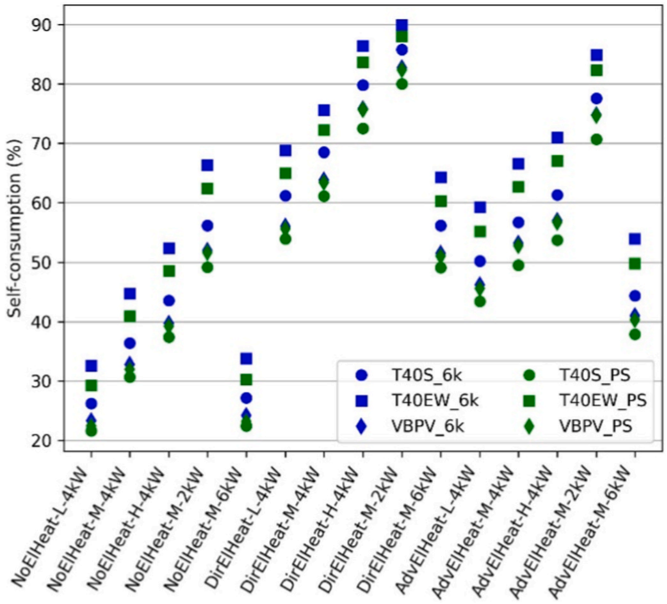

Fig. 11. Self-consumption rates of different house–PV combinations.

3.4. Resilience of the Finnish electricity market under high PV penetration

The key factor affecting the economic viability of a residential PV system is the possibility of self-consuming the produced electricity. Therefore, maximizing the amount of self-consumed electricity is the top priority for residential PV installations. Selling PV production to the grid is more profitable than self-consumption only in exceptional cases (high spot price, fixed-price electricity contract). Fig. 12 shows the correlation between economic value (per kW) and the self-consumed kilowatt hours for all simulated cases (6060 cases in total). The correlation coefficients for the data shown in Fig. 12 are 0.888 and 0.753 for the LR and ABC models, respectively.

In the national-scale analysis, a minor increase in PV production rapidly decreases the electricity price when the ABC model is used. However, this effect likely reflects model limitations (Section 2.2.2). The expected growth of flexible demand in Finland, from 2.4 GW in 2023 to 8.8 GW in 2033 [48] is a key enabler for PV capacity growth, and together with PV production curtailment, will reduce the negative price hours. The Nordic countries have high potential for demand response applications, especially in Norway and Sweden, and to some extent in Finland, due to electric heating [49]. Furthermore, the price elasticity of residential demand (consumers' tendency to save electricity when the

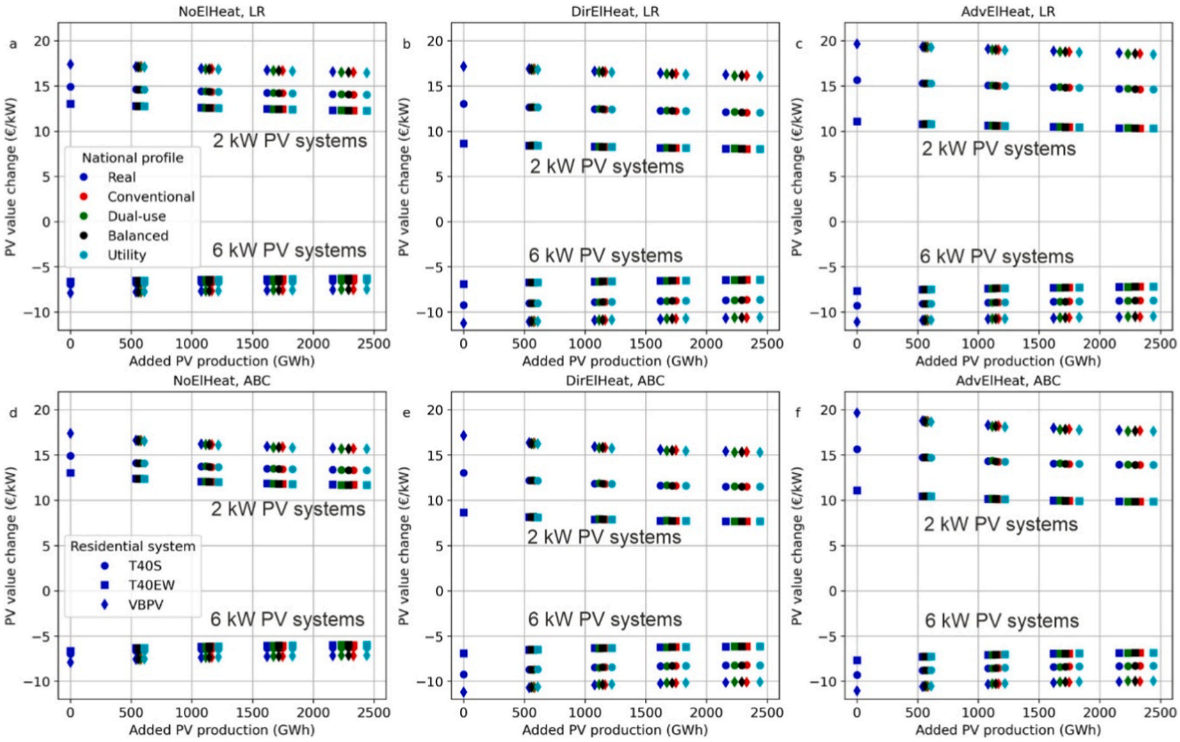

Fig. 10. Change in the residential PV (subplots a–c for LR and d–f for ABC) electricity across different scenarios for residential class NoElHeatM (a and d), DirElHeatM (b and e) and AdvElHeatM (c and f) when the PV system size is varied (±50 %).

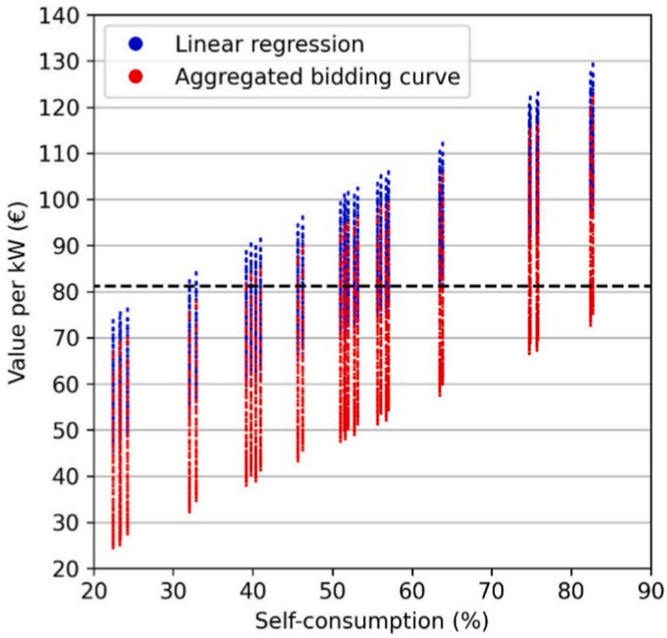

Fig. 12. Correlation of residential PV production value with residential self-consumption. The black dashed line indicates the threshold value to counter the initial investment costs (Section 3.2).

price is high) reduces price volatility [30]. Therefore, the results presented with the ABC model represent an extreme-case scenario.

PV production in Finland is low from December to January due to the northern location, making the role of PV in electricity generation negligible during these months. If thermal power plants are decommissioned as PV capacity increases, the available electricity production capacity in winter will be limited. In such cases, both the households and the national electricity system are vulnerable to market price peaks and electricity scarcity, as analyzed in Ref. [18]. Due to the current geopolitical situation in Europe, dependency on electricity imports can compromise energy security [19], although price elasticity and consumers' price-awareness cut the demand when the price is high [30]. Thus, addressing the challenges caused by variable PV production is critical to ensure the resilience of the power system with high VRE shares.

4. Conclusions

This study developed a set of electricity pricing scenarios and defined the economic value of annual residential PV production for PV systems with varying orientations and sizes using real electricity consumption data. To complete the analysis, we used PV production models based on a real operating system and commercial software, a large set of residential electricity consumption data from a local distribution system operator, and real electricity market data. The value of residential PV electricity under different national PV scenarios was estimated using two electricity price models: linear regression and aggregated bidding curve modification. Our results show that residential PV value cannibalization occurs rapidly without mitigation actions. Even with a 500 MW PV capacity addition, the majority of the simulated cases had a PV production value below the investment cost threshold. A high self-consumption rate provided economic resilience for PV systems, whereas the national PV deployment strategy had only a minor effect on residential PV cannibalization.

The key factors defining the total value of residential PV production (per kW) are self-consumption and national PV capacity. The systems with high self-consumption showed moderate resilience toward price cannibalization due to saved transmission fees and taxes, whereas low self-consumption made the systems vulnerable to cannibalization. Therefore, maximizing self-consumption is the key to the economic profitability of residential PV as national PV production increases. This work examines self-consumption maximization via PV system design, namely adjusting the size and orientation of the system to produce PV electricity when needed. Another approach at the residential level is the load shifting. However, we excluded this approach from our scope to isolate the potential of PV system design alone, without additional support from load shifting or energy storage. Electricity-powered heating enhanced PV profitability by increasing self-consumption. VBPV had superior performance compared with rooftop MPV due to improved production and load matching. The T40S-orientation had a higher value than T40EW, but the difference in the value was smaller than the difference in the production. Large south-facing PV systems should be avoided when feed-in tariffs are unavailable, as they can cause extensive overgeneration.

The ABC model produced a larger decrease in electricity price than the linear regression model. This phenomenon likely reflects model limitations and market behavior in the Nord Pool day-ahead market. However, the ABC-model provides a worst-case estimate of electricity price development from the PV producer's perspective.

Overall, the ongoing rapid change in the power system makes any investment vulnerable to electricity price uncertainties. For most electricity generation facilities, including PV, this phenomenon is significant due to high investment cost. For residential PV, self-consumption is key to protecting the economic profitability of the system under different electricity price development scenarios.

CRediT authorship contribution statement

Sami Jouttijärvi: Writing – review & editing, Writing – original draft, Visualization, Validation, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Simeon Seppälä:** Writing – review & editing, Writing – original draft, Methodology, Investigation, Formal analysis, Data curation. **Lauri Karttunen:** Writing – review & editing, Methodology, Conceptualization. **Samuli Ranta:** Writing – review & editing, Resources, Funding acquisition. **Sanna Syri:** Writing – review & editing, Supervision, Resources, Funding acquisition. **Kati Miettunen:** Writing – review & editing, Supervision, Methodology, Funding acquisition, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.renene.2025.125169.

Data availability

The publicly available and commercial datasets used in this work are referenced appropriately. The codes used by the first author are published in GitHub: https://github.com/energy-systems-team/codes-j.

renene.2025.125169.

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