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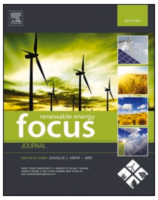

Research Paper

Economic viability of large-scale solar PV implementation in the Nordic power market: Case Finland

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ABSTRACT

This study analyses how the rapid growth of utility-scale solar PV in the Nordic region will impact its economic viability by 2030, using Finland as a case study. The analysis is based on modelling the Nordic electricity market. Solar energy is crucial for the energy transition in the Nordic region; however, high penetration levels pose significant economic challenges. The lack of feed-in tariffs for solar PV, limited energy system flexibility, high shares of nuclear and wind power and ambitious solar expansion plans make Finland a topical case study. Using PLEXOS advanced electricity market simulation tool, this study models the Nordic and Baltic multinational electricity system in detail and its connections to the Central Western European power market. The study includes significant electricity demand changes from rapid increases in electric vehicles, district heating electrification, and hydrogen production. Multiple scenarios representing different solar PV levels across the Nordic regions are analysed by 2030, including one scenario with various shares of vertically mounted, east-west-oriented bifacial solar PV. Results indicate that large-scale solar PV integration in the Nordic region could collapse Finnish electricity prices, specifically in the summer months. This expansion would reduce solar capture rates to 40% by 2030, highlighting the solar cannibalisation in Finland. These findings indicate the potential economic risks of extensive solar PV deployment and the need for market adaptation. Integrating vertical bifacial panels to adjust the PV production profile and optimising the electric vehicle charging are found to be important to improve the economic viability of solar generation.

Introduction

The transition to sustainable energy has become a global imperative, as it is essential for addressing climate change, ensuring energy security, and promoting sustainable development. The Nordic region is at the forefront of these global efforts, with an aim to achieve carbon neutrality in the next decades [1]. Finland's official plan is to achieve carbon neutrality in 2035 [2] Sweden in 2045 [3], Denmark in 2050 [4], and Norway in 2050 [5]. The EU Renewable Energy Directive sets a binding target for member countries to reach a 42.5% renewable energy mix by 2030 [6]. With these ambitious targets, Variable Renewable Energy Sources (VRES) like wind and solar have gained more significance in the energy transition process.

Hydro and wind power are already well integrated into the Nordic energy system. Hydropower is the most utilised renewable electricity resource in the Nordics, and the reservoirs in Norway represent approximately half of the total hydro storage capacity in Europe [7]. The flexibility given by the hydro capacity makes the region well-suited for the integration of VRES. Wind power is prominently integrated into the Nordic energy system, with Sweden, Denmark, and Finland having 19

Abbreviations: BEV, Battery Electric Vehicles; CHP, Combined Heat and Power; CO_2, Carbon Dioxide; CR, Capture Rate; CWE, Central Western Europe; DH, District Heating; ENTSO-E, European Network of Transmission System Operators for Electricity; EV, Electric Vehicle; LCOE, Levelised Cost of Electricity; LT, Long Term; M€, Million Euros; MT, Medium Term; NECP, National Energy and Climate Policies; NTC, Net Transfer Capacity; PASA, Projected Assessment of System Adequacy; PECD, Pan European Climate Database; PLEXOS, Energy system modelling and optimisation tool provided by the company Energy Exemplar Ltd.; PHEV, Plug-In Hybrid Electric Vehicles Solar PV, Solar Photovoltaics; SRMC, Short Run Marginal Cost; ST, Short Term; TYNDP, Ten-Year Network Development Plan; UR, Unit Revenue; V2G, Vehicle-to-Grid; VBPV, Vertically Mounted Bifacial Solar PV; VRES, Variable Renewable Energy Sources.

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GW [8], 7.5 GW [9], and 8.2 GW [10] of installed capacities by the end of 2024, respectively. A strong growth of wind power is expected to continue in the Nordics. Wind conditions between the northern and southern Nordics are divergent, with higher levels during winter than summer months. This seasonal variation aligns with the high power demand in winter, contributing to a balanced energy supply.

Solar energy is promising as an economically viable option. The levelized cost of electricity (LCOE) of solar is now competitive with other technologies [11]. This is mainly due to technological advancements, efficiency improvements in PV, and solar economies of scale. Both individuals and businesses are interested in solar PV option due to the economic benefits, for instance, in local production and consumption to avoid transmission and distribution fees and taxes. Since hourly PV and wind power production have a negative correlation in Finland, adding PV to the high-wind power system achieves synergies. The aggregated VRES (wind + PV) production profile will be smoother, and the grid infrastructure already built for wind power can fit PV with reasonable additional investments. The Nordic region has recently integrated a significant amount of solar PV into the energy system, also on utility scale. As of 2025, installed solar PV capacities in Denmark, Sweden, Finland, and Norway are 3.7 GW [9], 3.1 GW [9], 1.1 GW [12], and 0.7 GW [13], respectively. Further, solar PV will play a pivotal role in future energy system, according to the National Energy and Climate Policies of the Nordic countries [14-17].

Regardless of the economic benefits, solar energy is challenging due to its seasonal generation profile and time-dependent nature. The whole Nordic region experiences significant daylight time variation throughout the year. Short winter days with high electricity demand and long summer days with lower demand create a seasonal mismatch between solar energy supply and demand, although this mismatch is partially balanced by scheduling the annual maintenance of the nuclear power plants from spring to early autumn. Further, the Nordic area and the whole Europe exhibit similar solar generation peaks. Therefore, the market is saturated during the same peak hours in the region since there is no place to export excess electricity generated by solar. This situation leads to an oversupply of electricity relative to the demand. Since solar energy has zero marginal costs, it displaces higher-cost electricity generators in the merit order curve, leading to low electricity prices. In fact, the oversupply of electricity due to peak solar generation hours can worsen the concerns about cannibalisation, price collapses, and even negative electricity prices in extreme cases. Cannibalisation occurs when high penetration levels of a generation technology weaken the technology's own value in the wholesale electricity market. In recent years, this has been evident in Europe. For instance, the market prices dropped to the floor price of -500€/MWh in many Central Western European countries in the summer of 2023, and negative electricity price hours are becoming more frequent in the summer and autumn of 2024 (Finland had 427 and 725 negative electricity price hours in 2023 and 2024, respectively) [9]. These facts indicate the importance of studying the impacts of high solar PV penetration at the utility scale, *i.e.,* production to the power market.

The rapid growth of solar and wind power is also driven by the outlook for electricity consumption growth. According to Fingrid, the Finnish transmission system operator, electricity production in Finland may grow from 90 TWh in 2025 to even 130 TWh in 2030, fully due to the increase of wind and PV production [18]. Electric vehicles (EV) are in a key role in the reduction of carbon dioxide emissions from the transportation sector, and the target of the Finnish Government is about 925,000 EVs by 2030 [16]. There are also many projects under development to produce hydrogen from wind and solar power in Finland, *i.e.,* green hydrogen [19,20]. In addition, the trend of heating electrification is important to note when evaluating the electricity market prospects in Finland.

This study analyses the economic impacts of large-scale solar PV implementation in the Nordic power market by 2030 using Finland as a case study. This study aims to quantify the solar cannibalisation based on several future scenarios using PLEXOS Nordic electricity market model, considering different levels of solar deployments in different regions of the Nordic area and the foreseeable development of demand by the year 2030, including electric vehicles, hydrogen production and electrification of district heating. Section 2 presents previous literature on the topic. In section 3, the materials and methods used in this study are described. Section 4 presents the results of the study. In section 5, a comprehensive discussion of the implications of the analysis and suggested future work is presented. The last section draws conclusions by mentioning the key insights.

Literature review and novelty of this study

Studies have shown that residential scale PV systems have promising economic potential in Finland. Meriläinen et al. [21] studied optimised rooftop PV installations based on customer load profiles and demonstrated the optimum solar PV orientations to maximise revenue under southern Finnish weather conditions. This study suggests that single azimuth systems are profitable when the compensations are paid for the surplus electricity and optimal orientations at azimuth angles for -15° to 5° (with azimuth of 0° = south, angle increasing clockwise) with tilt angle between 35° to 45°. Shekar et al. [22] analysed the optimal azimuth for economically feasible rooftop solar PV installations at residential and community levels in Finnish Lapland. The study identified an optimal azimuth of -24° and emphasised the importance of location-specific optimisation in Arctic conditions. Several studies have explored the integration of solar PV systems with heating solutions in Nordic conditions, focusing on solar PV revenues. Rehman et al. [23] studied solar PV integrated with different heat pump-based district heating systems at the community level. They found that a centralised solar integrated district heating system with seasonal storage was the most cost-effective and environmentally friendly option. Hirvonen et al. [24] investigated small-scale building-integrated PV systems with economic support schemes. This study concluded that feed-in tariffs were the most effective in promoting solar PV integration, while investment subsidies were less impactful but more cost-efficient for the government. Meriläinen et al. [25] examined the profitability of solar PV-battery energy storage-heat pump systems for townhouses, considering different system designs. This study found that such systems could significantly reduce both energy costs and CO_2 emissions, with optimal sizing depending on electricity prices and available roof area. Beyond residential applications, the potential of integrating solar PV with specialised industrial sectors in Finland has been studied. For instance, Hyvönen et al. [26] showed that solar PV systems can cost-effectively provide renewable electricity to data centres in Finland and Japan. Simola et al. [27] demonstrated the optimal dimensioning of building-integrated solar PV plants for a dairy farm and a grocery shop. The most economically viable building-integrated PV options were found, as a 40 kWp system could cover a significant portion of the farm's electricity demand, while for the grocery shop, 60 kWp was found optimal.

Despite the wealth of these residential and specialised industrial sector solar PV optimisation studies, most of the current PV construction in Finland is utility-scale production for the power market [28-31]. With this utility scale solar PV boom in Finland, the economic viability of the future energy system is a crucial topic to understand. The total aggregated capacity of the planned utility-scale PV projects, 16 GW [32], is enormous compared with typical electricity consumption in Finland. With the seasonal and diurnal solar generation profiles, particularly solar cannibalisation threatens the viability of these projects.

These impacts on electricity price are studied for solar rich regions throughout the year. Kolb et al. [33] found that wind and solar PV significantly reduced German day-ahead electricity prices by 2.89–8.89 ct/kWh already during 2014 to 2018. Peña et al. [34] demonstrated that renewable expansion in Spain reduces market prices and revenues for both renewables and conventional plants due to cannibalisation and depredation effects. Reichenberg et al. [35] demonstrated in a recent study that the cannibalisation effect substantially lowers the projected profits of variable renewable investments, reducing profit margins and increasing the investment risk and the required thresholds as the market penetration increases. Furthermore, cannibalisation has been studied through both empirical data [34,36-38] and using modelling data [39-42]. López Prol et al. [36] studied cannibalisation in California, where increasing solar and wind penetration has led to a mutual decline in their respective capture rates. Hirth [37] identified the expansion of VRES as the major driver of the electricity price drop in Germany and Sweden between 2008–2015. An analysis of Zipp [38] depicted a reduction in average day-ahead price in Germany and Austrian region already during 2011-2013 with high VRE generation. Using a numerical European Electricity Market Model, Hirth [39] found that the value of solar declines faster than wind. An analysis of Lamont [40] depicts a 30%-40% VRE value depression in 2030 in California. Studies by Winkler et al. [41] and Blume-Werry et al. [42] show that fuel and CO_2 prices affect VRE market values and thus contribute to the emergence of potential solutions. However, in the Nordic region and in Finland, so far, very little attention has been paid to the economic impacts of large shares of utility scale solar PV.

One of the proposed solutions to reduce the economic impact of high solar penetration is the integration of energy storage systems with utility-scale solar PV. Ma et al. [43] and Schleifer et al. [44] show that an optimised hybrid energy storage system enhances flexibility and the shares of renewable energy. Nkwanyana et al. [45] and Bullich-Massagué et al. [46] emphasise improved system stability in the presence of electricity storage and selecting the most suitable technology. He et al. [47] demonstrate that portable utility-scale storage can increase revenues and support grid reliability.

Recent studies on vertically mounted bifacial solar PV (VBPV) in Finland provide evidence for its effectiveness in high-latitude conditions compared to conventional solar PV. This was experimentally proved on the residential scale [48] and proved with modelling results in both residential [49,50] and utility scale [50]. Jouttijärvi et al. [49] demonstrated using modelling that VBPV could achieve 7.4%–10.9% higher economic value compared to conventional solar electricity on the residential scale (*i.e.,* including self-consumption). Despite these findings, the economic impact of integrating VBPV into the energy system on a large scale remains an unexplored area of study, particularly in the context of Nordic countries.

Fig. 1 illustrates the differences in electricity generation profiles between conventional PV panels and VBPV panels at a southern Finnish location on a midsummer day. Conventional PV panels are installed at a tilt angle of 40° facing south, resulting in a single production peak at solar noon. In contrast, VBPV panels are mounted vertically (tilt angle 90°) with both east- and west-facing surfaces, leading to two production peaks, one in the morning and another in the evening.

There are several challenges to integrating solar PV in Finland compared to the other Nordic countries. Finland has little supply-side flexibility within the energy system. The energy mix consists of nuclear, hydro, wind, combined heat and power generation (CHP) and solar generation. Wind generation is intermittent, nuclear generation has low flexibility, and there are fewer flexible hydro reservoirs than in Norway and Sweden. CHP production is driven by the district or industrial heat demand, with electricity often being a by-product. Furthermore, unlike many other countries, neither Finnish onshore wind nor utility scale solar PV developments receive considerable subsidies. When considering recent electricity prices, and in particular negative price hours in 2024, Finland has the highest negative price hours (725 hours [9]) in Europe.

As highlighted by the literature above, Finland presents a topical case study for analysing the economic viability of large-scale solar PV deployment. Research is needed to understand how solar PV will affect electricity prices, the potential of VBPV to overcome the economic challenges of solar PV, the role of increasing electricity use in several sectors and applications, and thus, the overall energy system economics in the Finnish and the broader Nordic context.

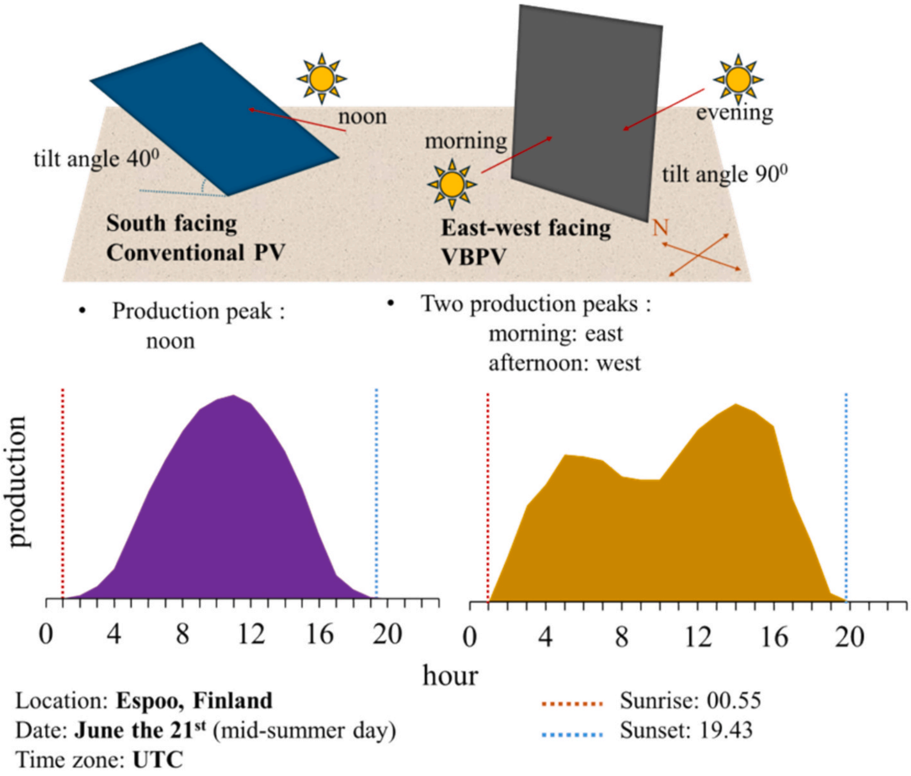

Fig. 1. Comparison of conventionally mounted south-facing solar PV and east-west faced VBPV.

Methods

This section presents a brief overview of the multinational electricity market, which is modelled in this study (Section 3.1). Section 3.2 presents the modelling tool and its main principles as applied in this study. Section 3.3 proceeds by describing the modelled multinational system in detail and by giving references to the detailed data sources. Sections 3.4 to 3.6 describe in detail the modelling of electrified district heating, electric vehicle fleet and production of hydrogen from electricity, respectively. In section 3.7, the solar PV capacity expansion scenarios created in this study are presented.

The Nordic and Baltic electricity system

In this study, the whole Nordic and Baltic electricity systems and their connections to Central-Western Europe (CWE) and Great Britain (GB) were modelled by utilising the PLEXOS advanced simulation tool. The multinational Nordpool Nordic and Baltic electricity market consists of fifteen bidding zones [51], which is illustrated in Fig. 2 The Nordic Bidding zones include Denmark (DK1, DK2), Finland (FI), Norway (NO1, NO2, NO3, NO4, NO5), and Sweden (SE1, SE2, SE3, SE4), and the Baltic bidding zones represent Estonia (EE), Latvia (LV), and Lithuania (LT). Further, Central-Western Europe (CWE) power market represents Germany (DE), the Netherlands (NL), and Poland (PL).

PLEXOS advanced simulation tool

PLEXOS is an advanced simulation tool that allows the modelling and optimisation of zonal and nodal energy systems through various planning horizons from 1-second granularity to decades ahead [52]. PLEXOS optimises the dispatch of power generators to meet the electricity demand, while cost minimisation and other objectives and constraints are considered. Several factors are counted in the modelling: the variable resource availability, costs of different technologies, transmission constraints, environmental regulations, and operational constraints defined by the user. In terms of the electricity market, PLEXOS considers the interaction of bidding and pricing mechanisms, determining the electricity price based on supply and demand balance, utilising several optimisation algorithms, including mixed-integer linear programming. In this study, PLEXOS was used to optimise power plant maintenance schedules, the use of hydro reservoirs across multiple years, and the short-term dispatch of generators. The main objective of PLEXOS in this study is to minimise system costs.

In this work, three schedules of PLEXOS are used: the medium term (MT), short-term (ST) and the Projected Assessment of System Adequacy (PASA). The MT schedule models the entire year with simplified details. MT simulates the year by changing the data into load duration curves, which are then split into blocks. The MT simulation results are sent to the ST schedule. For example, the MT schedule sends certain targets for hydro storage levels, which should be met by the ST schedule at the end of each ST period. The PASA optimises the maintenance schedules of thermal plants. ST Schedule is mixed-integer programming based on chronological unit commitment and economic dispatch model. In this work, a full chronology is used. The ST schedule has been configured to consist of 73 five-day periods in a normal year, and 61 six-day periods during a leap year. In this study, ST is configured to an hourly interval. In this study, the model is run ten times with ten distinct samples (weather years 2007-2016) in MT, ST and PASA.

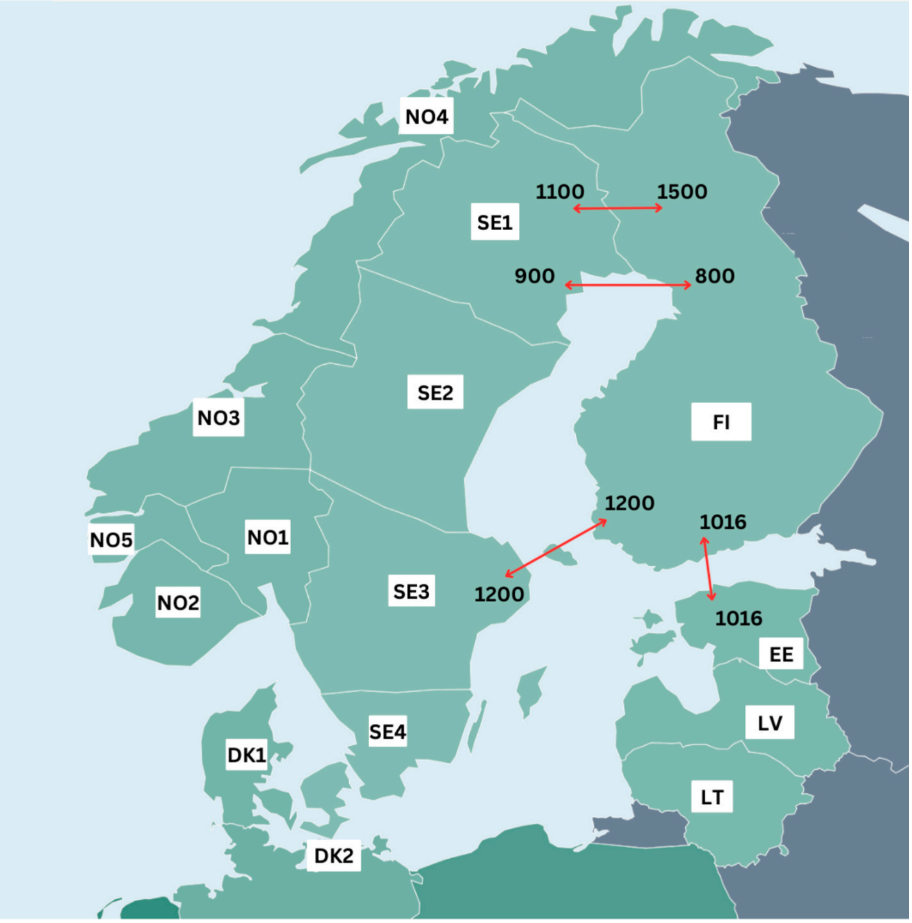

Fig. 2. The Nordic and Baltic Bidding Zones of the Nordpool electricity market, which are modelled in detail in this study [51]. Transfer capacities for Finland are shown as Net Transfer Capacities (NTC).

A simplified objective function with the main constraints representing the modelled system is presented below in Eq. (1):

$$\begin{gathered} min\sum_{t=1}^{T} c_{elect.\,SRMC,t} + c_{heatSRMC,t} \\ st. \\ electricitybalance \\ heatbalance \\ hydroconstraints \\ storageconstraints \\ transmissionconstraints \end{gathered} \tag{1}$$

where

$c_{\mathrm{elect.SRMC,t}}$ equals Cost of Electricity (Short run marginal cost of electricity) at hour t

$c_{\mathrm{heat.SRMC,t}}$ equals Cost of Heat (Short run marginal cost of heat) at hour t

The MT and ST schedules of PLEXOS aim to minimise the sum of costs from electricity and heat generation during the modelled year. These are represented by the short-run marginal costs (SRMC), i.e., the variable operation and maintenance costs, cost of startup and shutdown, fuel costs and emission costs. T is 8760 hours during a normal year. The main constraints within the model are the electricity and heat balance constraints, which mean that the hourly demand must be met either with generation or from storage. Hydro constraints relate to hydro dispatch, storage, and inflow constraints, while storage constraints relate to similar constraints present within the electricity and heat storages. Recycling storage was included in this model, meaning that all hydro reservoirs and other storages must have the same content at the end of the modelling period as in the beginning. Transmission constraints regulate the transmission of electricity between the modelled regions (Fig. 2). In this paper, the Long-term schedule was not used. Thus, investment costs have no impact on the objective function, and no capacity optimisation was conducted.

Modelling the Nordic and Baltic energy system

The fifteen Nordic and Baltic bidding zones (Fig. 2) are modelled individually and interconnected by transmission lines. CWE markets and GB are simplified as hourly electricity price profiles and transmission limits. The applied price profiles are based on historical actuals [9] with annual scaling according to power market forward curves for 2024-2030 [53]. The Net Transfer Capacity (NTC) values are used as the transmission limits within the modelled bidding zones and to the external boundary markets (CWE and GB) in the model [34]. Fig. 3 presents a simplified flowchart of the modelling conducted in this study. All major power plants (installed capacity above 100 MW) are modelled with representative technical parameters, for instance, the consumed fuels, heat rates, ramping rates and the minimum stable levels. The corresponding CO_2 emission rates and market prices are included under fuel properties.

In this modelling, electricity generation is dispatched by ascending marginal costs. Wind and solar generation are assumed as zero marginal costs, and nuclear power has a low marginal cost, thus dispatched before fossil and biomass-based generation. Power plant maintenance rates are optimised based on historical availabilities as input parameters. CHP generators are aggregated as one generator per bidding zone (FI and DK), where the fuel mix is represented as ratios. Power plant installed capacities for 2024 in the model are based on the Transparency Platform managed by the European Network of Transmission System Operators for Electricity (ENTSO-E) [9], and the 2030 installed capacities are determined based on National Energy and Climate Policies (NECP) [54]. Furthermore, fundamental Nordic power system data were obtained from ENTSO-E [9], Fingrid [55], Finnish Energy Authority [56], and utility websites. Additionally, essential technical information related to power plants and commodity prices were gathered from diverse research articles and reports.

Solar, onshore wind, offshore wind, run-of-the-river hydro, and pumped hydro are aggregated as one generator per technology per bidding zone. These hydro reservoirs were set to recycle, *i.e.*, the reservoir levels at the end of the optimisation horizon (end of each year)

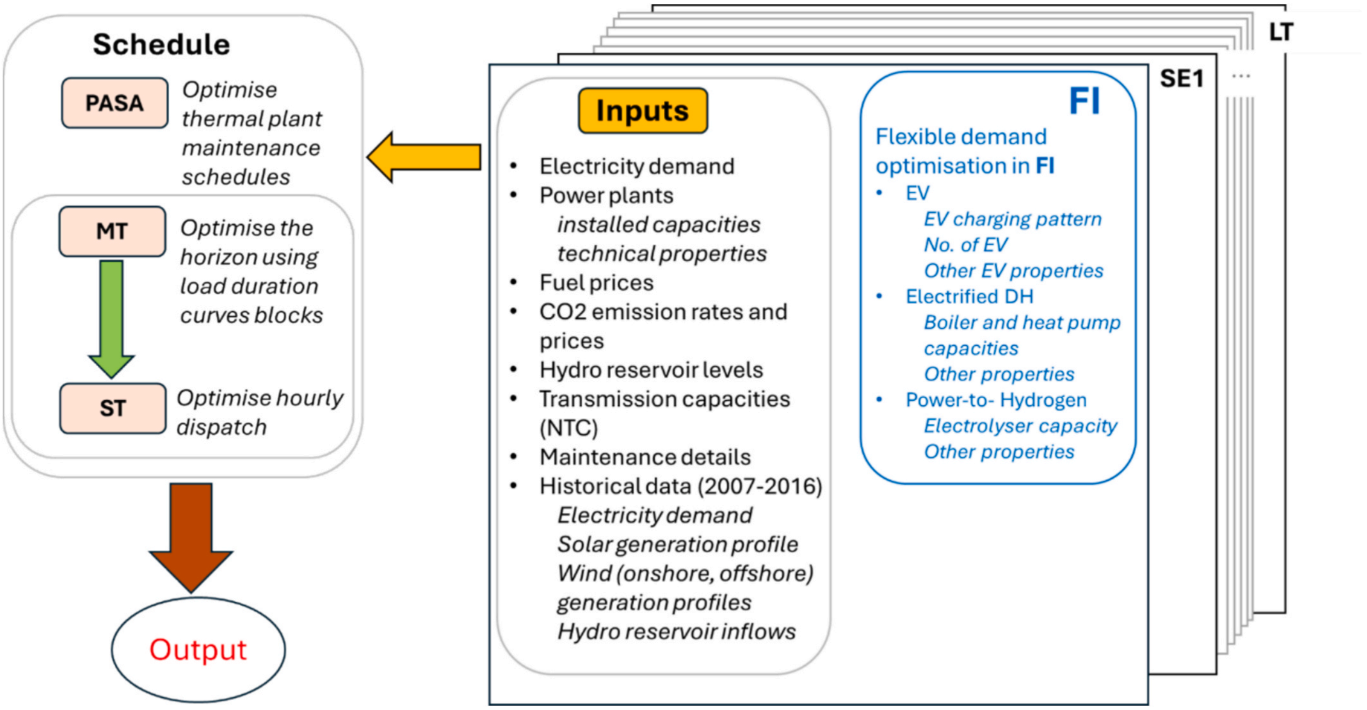

Fig. 3. Modelling flowchart. 15 bidding zones are represented in layers, FI, SE1, SE2, SE3, SE4, NO1, NO2, NO3, NO4, NO5, DK1, DK2, EE, LV, LT (for abbreviations, see Fig. 1).

need to match the initial values (beginning of each year). Hydro reservoir levels (initial, minimum and maximum reservoir levels) are based on the average storage values at the beginning of the year, based on 2016-2023 data [9]. The modelling in this study uses solar and wind profiles, and hydro inflow profiles for each Nordic and Baltic bidding zone, from the period 2007 to 2016.

Electricity demand for all the bidding zones by 2024 is based on ENTSO-E [9] demands. Electricity demands by 2030 are determined based on the Ten-Year Network Development Plan (TYNDP) [57] and NEPC [54]. Historical demand profiles for each Nordic and Baltic bidding zone from 2007-2016 are used in this study. Since the main focus of the model is on Finland, electricity demand for the Finnish heating sector is modelled separately (Section 3.4). Similarly, Power to Hydrogen and Electric Vehicle demand are modelled separately for Finland (Sections 3.5 and 3.6). For other bidding zones, these demands are included in the total demand of the bidding zones.

The historical datasets from 2007-2016 (electricity demand profiles, solar and wind generation profiles, and hydro inflows) were sourced from the Pan European Climate Database (PECD) [58]. By incorporating this historical data, the model simulates variations in power demand, hydrological conditions, and renewable energy generation. This approach allows the modelling to capture a wide range of potential weather-related impacts on electricity market dynamics and price fluctuations.

The installed capacities of fossil fuel, nuclear, hydro and wind power plants by 2030 are shown in Table 1. Solar PV installed capacities and electricity demand levels for 2024 and 2030 are shown in Table 2.

Electrification in the heating sector

The expected transformation of Finland's District Heating (DH) sector is modelled based on an analysis of Koivunen [59]. Respective electric boilers, heat pumps, heat only boilers and CHP maximum capacities used in the model are described in Table 3. Electric heating in individual homes is included in the total electricity demand (Table 2). Fig. 4 shows the simulation results of the electricity demand in district heating calculated as the mean of weather years 2007-2016.

Power to Hydrogen

Green hydrogen (hydrogen generated using renewable electricity) production in Finland is modelled separately within this model. The minimum annual hydrogen production in 2030 is assumed as 11,000 TJ (approximately 3,055 GWh), and an electrolyser capacity of 500 MW in the model. According to the NECP 2024, Finland aims to supply 10% of the EU's green hydrogen demand [16]. However, considering the current installed electrolyser capacity, as well as planned and delayed hydrogen production projects [20], a 500 MW electrolyser capacity by 2030 was considered a reasonable assumption for Finland. The efficiency of electrolysers is assumed as 70%. Thus, hydrogen production is required to operate with about 8700 full load hours, and the model focuses on the part-load during the most expensive hours. Fig. 5 shows the modelling results of the electricity demand in power-to-hydrogen calculated as the mean of the weather years 2007-2016.

Table 1
The Nordic and Baltic installed generation capacities in 2030, as assumed in this study [GW] [54].

Technology	FI	SE	NO	DK	EE	LT	LV
Nuclear	4.39	6.9	-	-	-	-	-
Wind onshore	10	24		5.7	1.3	2	0.3
Wind offshore	1	1.8		7.7	1	2.1	0.7
Hydro	3.2	13.0	28.9	-	-	2	1.4
Oil	-	0.6	-	-	-	-	-
Gas	-	0.12	0.7	-	0.7	0.75	0.28
Oil shale	-	-	-	-	1.75	-	-
CHP	5.25	-	-	7.3		-	-

Table 2
Base case solar installed capacities and demands used in the model for 2024 [9] and 2030 [49,52].

Bidding Zone	Solar Installed Capacity 2024 [GW]	Solar Installed Capacity 2030 [GW]	Electricity Demand 2024 [TWh]	Electricity Demand 2030 [TWh]
DK1	2.7	12.9	22	34
DK2	0.9	4.7	14	21
EE	0.8	1.2	8	9
FI	1.1	5.8	85	105*
LT	1.1	5	12	18
LV	0.3	0.5	7	10
NO1	0.2	0.9	35	45
NO2	0.2	0.9	36	47
NO3	0	0	28	32
NO4	0	0	21	25
NO5	0.2	0.9	17	21
SE1	0	0	11	11
SE2	0	0	16	20
SE3	2.5	7.9	85	103
SE4	0.6	2.1	22	28

[*] Does not include the EV, Electricity demand in district heating and Power-to-Hydrogen demand in Finland

Table 3
Heat plants, electric boilers, large heat pumps and CHP maximum capacities in the Finnish DH sector.

Heat category	Maximum capacity by 2024 (GW)	Maximum capacity by 2030 (GW)
Electric Boilers	0.38	2.27
Heat pumps	0	0.7
Heat only Boilers	14.96	14.96
CHP DH	3.10	2.71

Electric vehicles

As of October 2024, Finland's electric vehicle (EV) fleet comprised 109,000 battery electric vehicles (BEVs), 161,000 plug-in hybrid electric vehicles (PHEV), and 5,000 other EV types, including BEV and PHEV vans, trucks, and buses [60]. Since passenger cars dominate the EV category, EV demand was modelled primarily by grouping all BEVs and PHEVs into a single category, totalling 270,000 in 2024. According to Finland's National Energy and Climate Policy [16], the total number of BEVs and PHEVs is expected to reach 925,000 by 2030, alongside 2,400 electric trucks. Based on this, the total EV fleet by 2030 was assumed as 925,000 in Finland.

EV charging patterns are modelled based on an analysis from [61]. EV properties, including average energy consumption (0.22 kWh/km), battery size (96 kWh), and charging power (11 kW), are based on the currently available EVs [62]. EV charging is optimised based on the driving patterns and properties. The present vehicle-to-grid (V2G) infrastructure limitations and technical constraints within the EVs are likely to limit significant energy discharge by vehicles. Given that 2030 is only five years from now, bidirectional charging is unlikely to play a significant role. Thus, V2G was excluded from this model. Fig. 6 presents the modelling results of the electricity demand in power-to-hydrogen calculated as the mean of the weather years 2007-2016.

Solar PV implementation scenarios developed in this study

Four different solar PV implementation scenarios with different solar capacities in the Nordic regions were considered. All the scenarios start from the same fundamental system with linear interpolation for e.g. wind and solar capacities and power demand between 2024 and 2030.

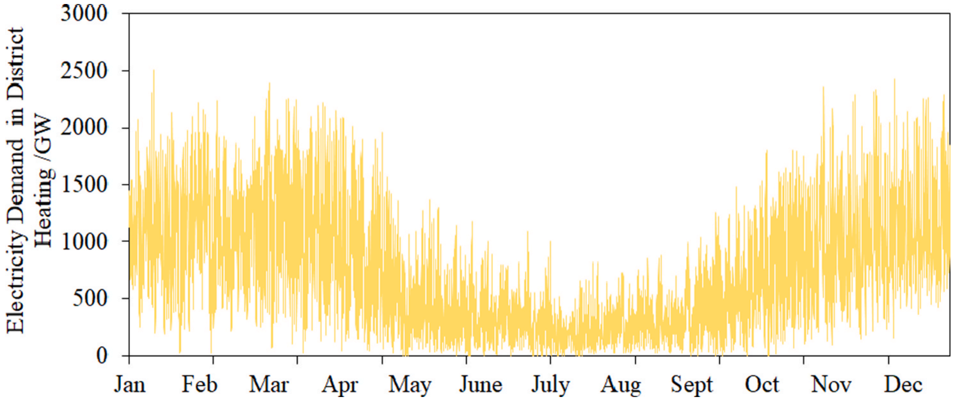

Fig. 4. Electricity demand in district heating during the year 2030 (calculated using the mean of 2007-2016 weather years).

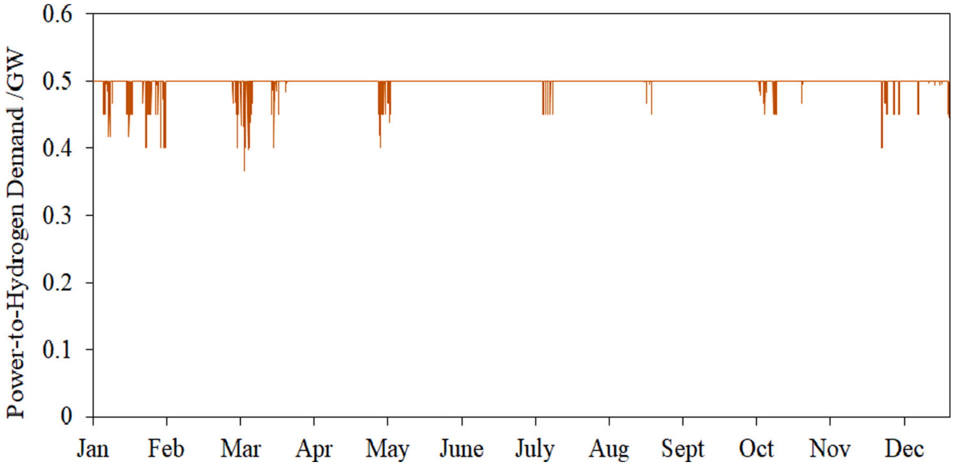

Fig. 5. Power-Hydrogen Demand during the year 2030 (calculated using the mean of 2007-2016 weather years).

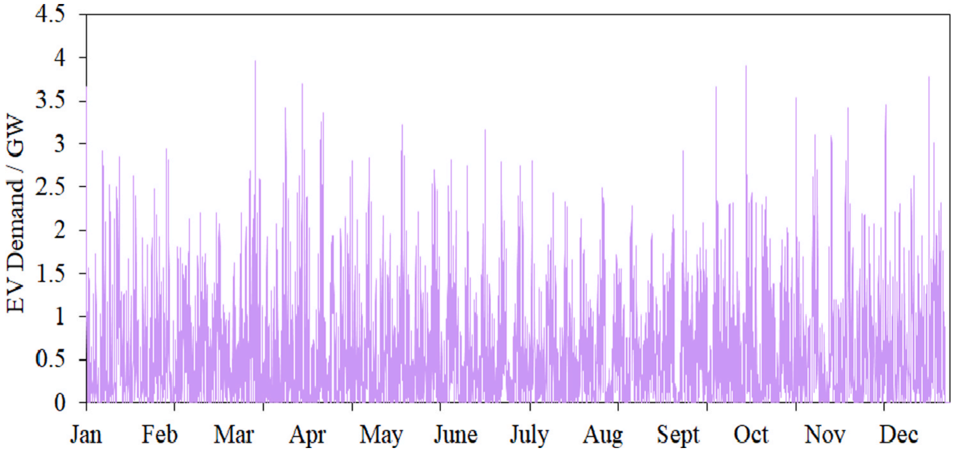

Fig. 6. EV electricity demand during the year 2030 (calculated using the mean of 2007-2016 weather years).

Ten independent weather years from 2007-2016 are used for sampling in the analysis.

Table 4 represents the scenario description in brief. Scenario 1 is the Base case with the current outlook for solar PV and other fundamentals. Scenario 2 considers additional solar power capacity in Finland, Scenario 3 considers additional solar expansions in the southern parts of the Nordics (DK1, DK2, SE3, SE4, NO1, and NO2), and Scenario 4 is a combination of Scenarios 2 and 3. The solar power increase in the southern Nordics affects the Finnish electricity market due to the possibility of importing more cheap solar electricity to Finland. In Scenarios 1-4, the solar PV production profile remained as it is, the only variable being the PV capacities. In Scenario 5, the effect of the PV production profile on cannibalisation is studied by integrating various shares of VBPV. Since Scenario 4 is the more extreme scenario with high solar capacity, Scenario 5 is modelled using Scenario 4, replacing 10%-40% of total solar capacity by VBPV in 2030. This change resulted a different production profile due to the production shift from noon to morning and evening, and a minor (+16 MWh/MWp) change in the total

Table 4
Description of the scenarios developed in this study.

Scenario	Description	Installed capacity in Finland by 2030 (GW)
Scenario 1/Base Case	Continue with current policies, strategies, and plans	5.8
Scenario 2	Additional Solar Capacity Expansion in Finland	11.6
Scenario 3	Additional Solar Capacity Expansion in southernmost Nordic bidding zones-NO1, NO2, SE3, SE4, DK1, DK2	5.8
Scenario 4 (a combination of Scenarios 2 and 3)	Additional solar capacity in Finland and southernmost Nordic bidding zones-NO1, NO2, SE3, SE4, DK1, DK2	11.6
Scenario 5	10%,20%,30%, and 40% solar PV capacity in Scenario 4, replace with VBPV in Finland	see Table 5

annual production. Respective conventional solar PV capacity and VBPV capacity used in Scenario 5 are shown in Table 5. Replacing more than 40% of the solar PV capacity with VBPV would not be realistic by 2030; thus, such scenarios are not considered in the analysis.

These VBPV profiles are calculated based on the hourly PV production profiles of 1 MWp power plants with south-facing monofacial panels (40° tilt) and VBPV panels in five locations in southern Finland, chosen to represent the sites of the largest PV plant under construction (60.82°N, 21.58°E) and the four largest PV plants under permitting stage (60.98°N, 27.95°E, 62.30°N, 22.38°E, 61.15°N, 22.60°E, 61.49°N, 21.98°E) based on publicly available information [32]. The calculations were done with commercial PVSyst software, using bifaciality factor of 80% for bifacial panels. For each location, the production was calculated using the "Generic 700 Wp 36V Twin half-cell" panels and "Generic 1000 kW 70 – 1300 W central inverter" from the PVSyst library. The row spacing was 8 m for the MPV and 30 m for the VBPV panels. Thus, replacing MVP with VBPV increases the required land area, but the sparse row spacing allows dual-use of land to balance the land-use costs. The average productions from the five locations were used to modify the national PV production profile.

Using this VBPV profile and conventional PV generation profiles from 2007-2016 (which are used in the model), VBPV profiles are calculated for each respective weather sample (2007-2016). Fig. 7 compares the average daily VPBV and conventional PV profile for each month, representing the weather year 2007.

Methods of quantifying cannibalisation

To study the cannibalisation effect of solar PV, Unit Revenue (UR) and Capture Rates (CR) are used as indicators. The UR (Eq. (2)) of PV shows the revenue per generated MWh (unit: €/MWh). The UR of PV decreases as the solar PV production increases, since the electricity price decreases during the peak PV production hours. This decrease in UR shows the average value decrease of a PV-generated MWh in Euros, and it is referred to as absolute cannibalisation. The CR (Eq. (3)) of PV compares the UR of PV to the average electricity price. A CR of 100% means that the UR of solar generation equals the average electricity market price for the considered period. A CR below 100% indicates that the PV-generated electricity is less valuable than the market average. The decrease of CR, which indicates how much PV-generated electricity value drops with respect to the average electricity price in the wholesale market as the solar penetration increases, is referred to as relative cannibalisation.

Table 5
VBPV solar capacities used for 2030 in Scenario 5.

Scenario 5	VBPV capacity (GW)	Conventional Solar PV capacity (GW)
10% VBPV	1.16	10.44
20% VBPV	2.32	9.28
30% VBPV	3.48	8.12
40% VBPV	4.64	6.96

Eqs. (2) and (3) calculate UR and CR [57,58]:

$$UR = \frac{\sum_{1}^{8760} ph.qh}{\sum_{1}^{8760} qh} \tag{2}$$

$$CR = \frac{UR}{\sum_{1}^{8760} ph} \tag{3}$$

where

ph is the hourly time-weighted electricity price and

qh is the hourly solar generation.

Based on the model simulation results, cannibalisation impact is quantified as UR and CR, using the mean of 2007-2016 ten independent weather years, which alleviates the impacts of any extreme weather events.

Results

This section describes the results of the scenario analysis. Section 4.1 describes the Electricity consumption of 2030 in the model. Sections 4.2-4.3 present the results of scenario analysis in detail. The base case presents the current outlook of the solar capacity, Scenario 2 considers additional solar capacity in Finland, and Scenario 3 considers additional solar capacity in the southernmost bidding zones of the Nordics. Scenario 4 presents additional solar capacity in the southern Nordics and Finland. Section 4.4 discusses the possibility of reducing solar cannibalisation by integrating VBPV with Scenario 4 (Scenario 5). Section 4.5 shows the role of flexible demand in integrating solar PV, and Section 4.6 discusses the renewable curtailment in the model.

Electricity Demand

Fig. 8 depicts the total electricity demand and consumer demands in Finland by 2030. Total Electricity demand is 117.2 TWh, which consists of 101.3 TWh consumer demand, 6.5 TWh electricity demand in DH (section 3.4), 3.4 TWh Power-to-Hydrogen demand (section 3.5), and 5.1 TWh EV demand (Section 3.6) as represented in Eq. (4). Consumer demand is the demand from all consumers, including households and industries. These demands are represented based on the mean of 2007-2016 weather years, as weather impacts significantly, especially in electricity demand in DH. In the model, total demand is represented as:

$$\begin{aligned} TotalElectricityDemand &= Consumerdemand \\ &+ ElectricitydemandinDistrictHeating + EVDemand + Power - to \\ &- HydrogenDemand \end{aligned} \tag{4}$$

Fig. 9 illustrates the variation of flexible demand with electricity price and solar generation in the First week of June 2030 as a representative week of summer in general. Electricity prices exhibit fluctuations, with lower prices occurring during periods of high solar generation. EV demand closely follows this trend, with increased charging activity during low-price periods, suggesting price-responsive behaviour. Similarly, DH electricity demand exhibits a similar but less pronounced pattern, indicating that both EV charging and DH demands are aligned with lower electricity prices to optimise cost efficiency.

Variation of electricity price and solar generation

Table 6 highlights the seasonal impact of increasing solar capacity on electricity prices in Finland by 2030. Solar generation peaks in the second and third quarters, coinciding with the lowest electricity prices.

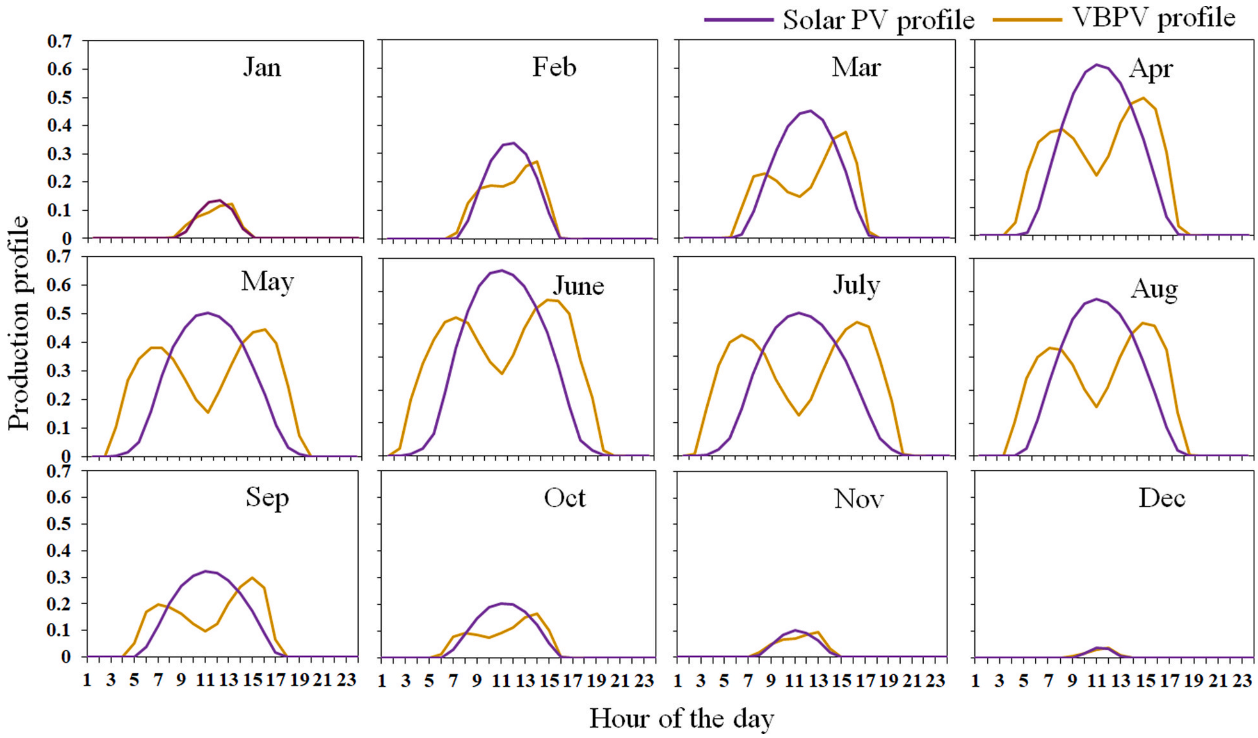

Fig. 7. Comparison of average daily conventional solar PV profile and VBPV profile, representative weather year 2007. The profile is shown as the ratio of the theoretical maximum generation; thus, it is unitless. (Time zone: UTC (Coordinated Universal Time)

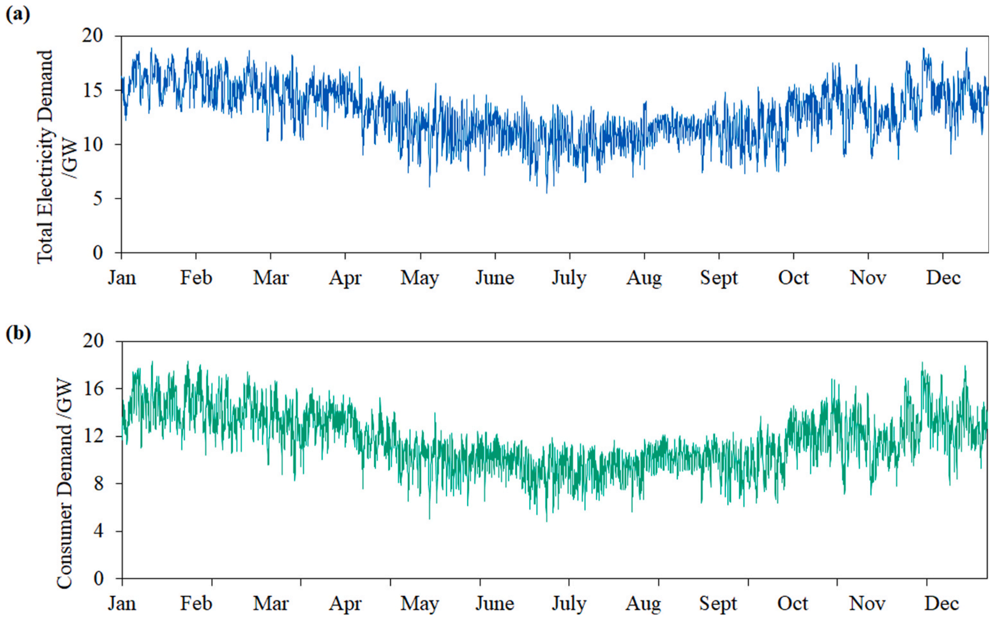

Fig. 8. Electricity demand in Finland in 2030 (Calculated as the mean of 2007-2016 weather years) (a) Total demand (b) Consumer demand (excluding electricity demand in district heating, in EVs and in hydrogen production).

The price decline is most pronounced in Scenario 4, where a substantial drop is observed in Q2 and Q3 (April-September) compared to the Base case. While Scenario 2 and Scenario 3 show similar price trends in Q1 and Q4, Scenario 2 leads to lower prices in Q2 and Q3. These results emphasise the inverse relationship between solar generation and electricity prices, with higher solar penetration driving price reductions, particularly in summer months.

Table A1 presents the average annual electricity prices for all the modelled regions in 2030. It can be seen that there will still be significant variations in electricity market prices between the regions, the Baltic countries having the highest prices and northern Sweden the lowest.

Fig. 10 shows the average electricity price variation of a day (24h) from May to September 2030 across four scenarios using 2013 as a representative weather year. A significant midday price drop is shown, particularly in Scenarios 2 and 4, where additional solar PV capacity is deployed. Scenario 4 shows the steepest midday price dip, highlighting the compounding impact of regional solar deployment. This price

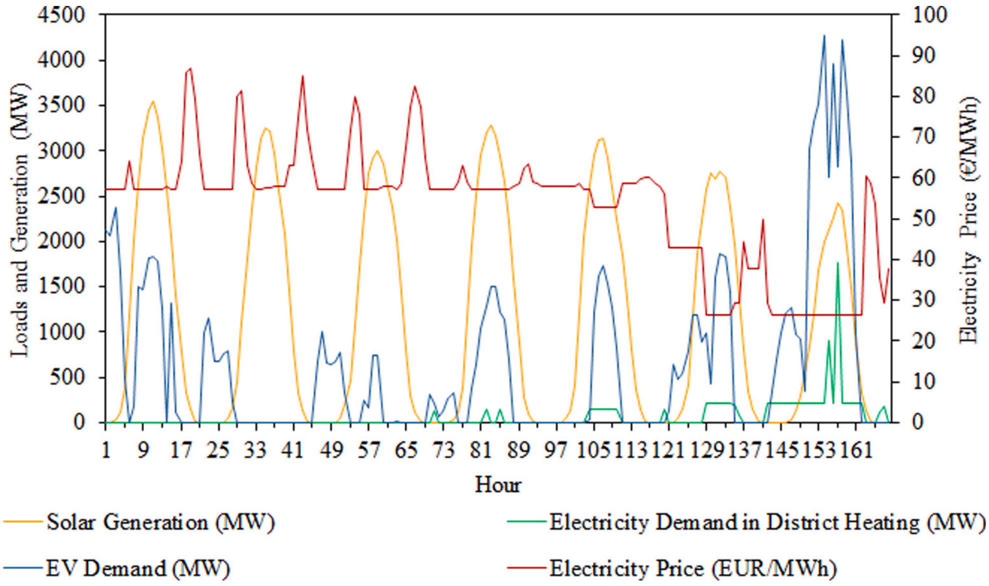

Fig. 9. Load variation with Solar Generation and Electricity price in the first week of June 2030, weather 2013 in Base case. During this week, hydrogen production was operating at a constant 500 MW load. EV charging is optimised (Section 3.6).

Table 6
Average hourly electricity price and total solar PV generation in four quarters of the year 2030. (Q1=January-March, Q2=April-June, Q3=July-September, Q4=October-December).

Scenario	Average Electricity Price (€/MWh)				Total Solar PV generation (GWh)			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Base case	84.87	45.86	44.82	40.97	742	2157	1743	351
Scenario 2	80.76	36.28	33.34	37.47	1485	4317	3488	701
Scenario 3	81.65	42.45	41.24	36.9	742	2157	1743	351
Scenario 4	77.23	31.54	27.8	33.5	1485	4317	3488	701

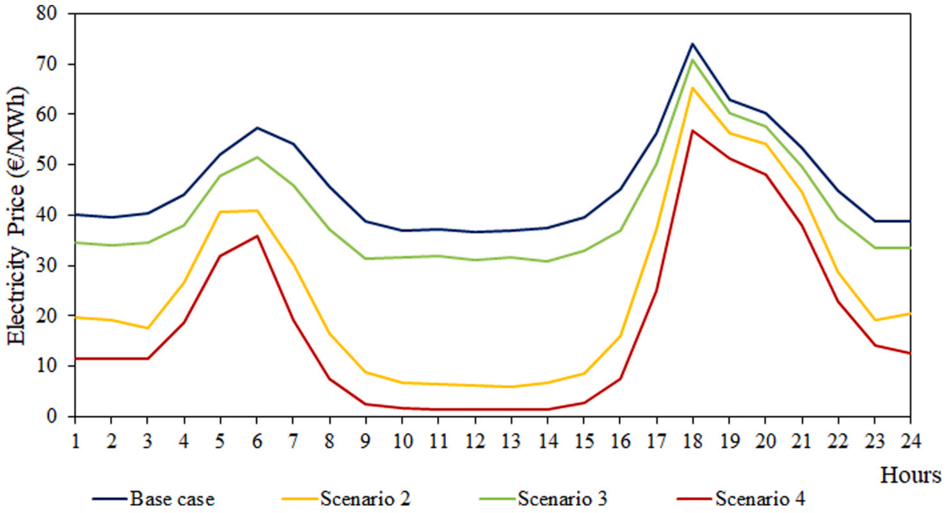

Fig. 10. Average hourly electricity price in Finland across scenarios from May to September 2030 (representative Weather year 2013).

depression during the midday hours is a result of the increased solar generation. During the nighttime, electricity prices are lower due to the lower demand.

Fig. 11 depicts the variation in solar generation and electricity prices during the first week of June 2030 as a representative summer week, in Finland across all four scenarios referring to the weather year 2013. It is evident that the electricity price fluctuates dramatically during the weekdays, and fluctuations during the weekends are comparatively lower. In the Base case, the electricity price fluctuates between 20 €/MWh to 85 €/MWh, on average. In Scenarios 2 and 4, the price goes below 10 €/MWh. In Scenario 4, prices decline to zero more frequently compared to Scenario 2. Notably, when the solar generation is high, the electricity price goes down in scenarios 2 and 4. These factors imply the impact of solar PV expansion on the electricity price in summer.

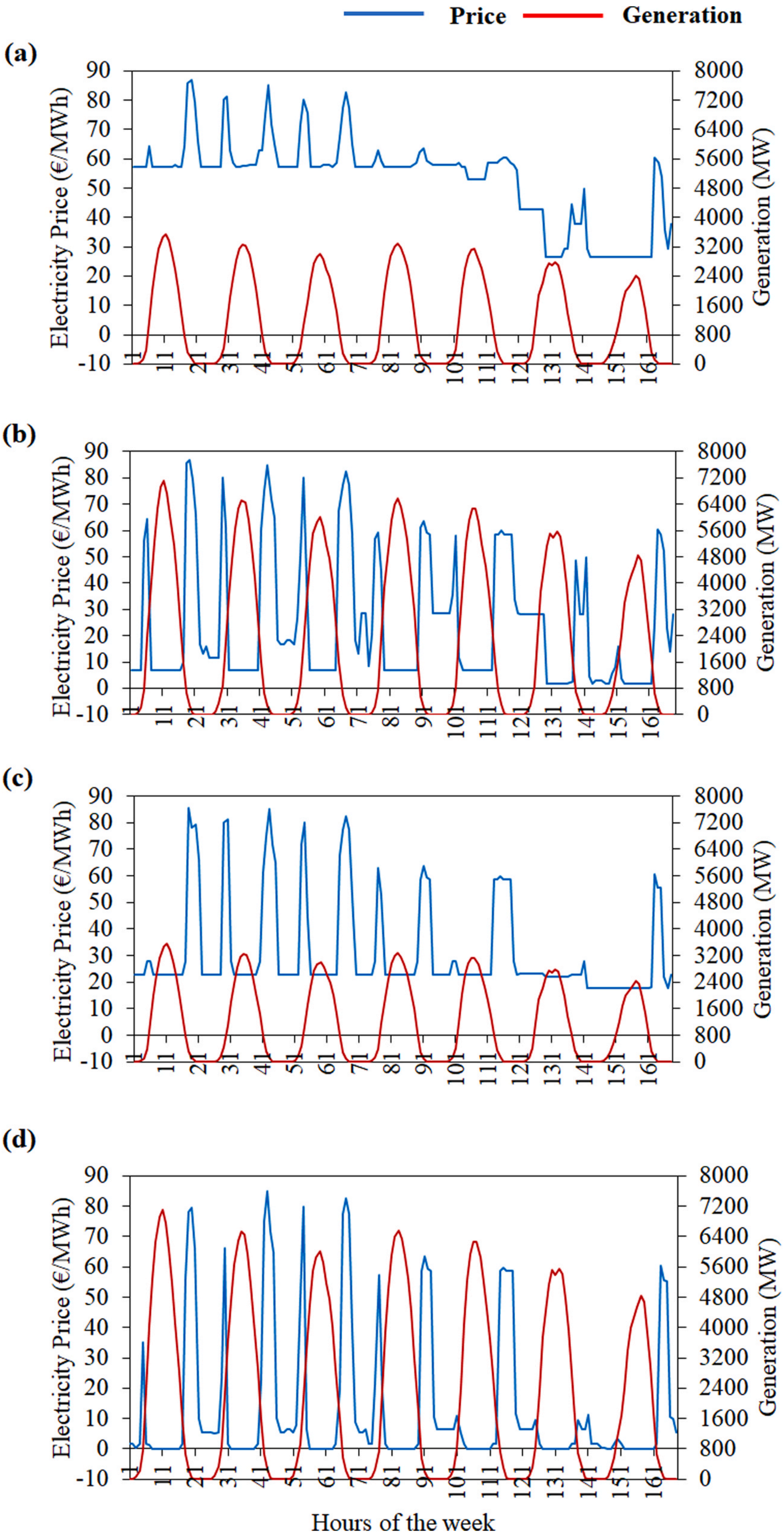

Fig. 11. Weekly electricity price and Solar generation variation in Finland during the first week of June 2030 (The weather year 2013) in (a) Base case (b) Scenario 2 (c) Scenario 3 and (d) Scenario 4.

Table 7
CR and UR values for 2030 across all the scenarios. These are calculated based on the mean of ten weather samples from 2007-2016.

Scenario	Annual Electricity Price (€/MWh)	UR (€/MWh)	CR (€/MWh)
Base case	53.98	40.98	76 %
Scenario 2	46.80	25.64	55 %
Scenario 3	50.41	35.21	70 %
Scenario 4	42.36	16.95	40 %

Unit Revenues and Capture Rates

Table 7 presents the annual average electricity prices, UR and CR in 2030 across four scenarios calculated based on the modelling results by using the mean of ten weather samples from 2007-2016. In the base case, 76% of the average electricity price is captured by solar PV electricity (CR = 76%), while with additional solar PV capacities (other scenarios), the fraction that solar electricity captures declines. The Base case CR and UR indicate a relatively stable current market outlook. Scenario 2, with additional capacity only in Finland, leads to a moderate decline. Scenario 3, where solar expands in the southern Nordics, results in a less severe impact on CR and UR than Scenario 2: in this case, the cannibalisation results from the electricity import to Finland from the southern Nordics. However, Scenario 4, where the PV capacity increases in both Finland and the southern Nordics, causes the sharpest decline with 40% CR. This indicates that the value of solar PV electricity is less than half of the annual electricity market price, highlighting the decreasing value of solar electricity, *i.e.,* solar cannibalisation in Finland.

Impact of bifacial solar panel integration (Scenario 5)

Table 8 compares Scenario 4 with Scenario 5, which includes different levels of VBPV integration. By 2030, total solar generation increases from 9,991 GWh in Scenario 4 to 10,754 GWh with 10% VBPV integration and continues to rise slightly as the share increases. The annual revenue depicts a notable increase by 14 M€ with a 10% VBPV share, with each additional 10% share contributing an additional 8–9 M€ revenue. While the average annual electricity price remains relatively stable, UR and CR show a modest improvement with higher VBPV shares. CR increases modestly from 40% in Scenario 4 to 47% with 40% VBPV. This increase results from the production shift from the noon to the morning and evening, which provides improved match with the electricity load and avoids the most severe cannibalisation hours around noon. Still, the value of solar PV generated electricity is less than half of the average annual electricity price

Table 8
Scenario 5 results for 2030. These are calculated based on the mean of ten weather samples from 2007-2016.

Scenario	Annual total Generation (GWh)	Total Annual Revenue (M€)	Average annual electricity price (€/MWh)	UR (€/MWh)	CR
Scenario 4	9991	169	42.35	16.95	40 %
10% VBPV	10754	183	41.41	17.03	41 %
20% VBPV	10805	192	41.14	17.77	43 %
30% VBPV	10856	200	40.82	18.39	45 %
40% VBPV	10906	208	40.62	19.06	47 %

Table 9
Average electricity market price, annual solar revenues, CR and UR for the year 2030 with and without flexible demands.

Scenario	Annual Solar Revenue (M€)	Annual Electricity Price (€/MWh)	UR (€/MWh)	CR
Base case	205	53.98	40.98	76 %
Base case – No flexibility	213	62.91	42.76	68 %
Scenario 2	256	46.80	25.64	55 %
Scenario 2 – No flexibility	257	55.48	25.75	46 %

Impact of flexible demands

Flexibility in demand plays a crucial role in integrating VRES. Table 9 shows a comparison of the annual average electricity price, annual solar revenues, UR and CR with and without flexible demand. In the no-flexibility case, EV charging, district heating electricity demand, and power-to-hydrogen demand are treated as fixed loads, meaning they do not respond to price signals but are instead included in the total demand. The results indicate that flexibility in demand lowers the electricity prices and solar revenues while significantly increasing CR in both the Base case and Scenario 2. However, in practice, it is uncertain whether EV owners would adjust their charging behaviour as optimally as modelled. Further research is needed to assess the real-world status and prospects of demand-side flexibility.

Renewable electricity curtailment

In many parts of the European electricity market, high wind and solar generation often exceed demand, leading to curtailment. This model assumes that wind (onshore and offshore) is curtailed before solar (PV and VBPV) at a market price of –5€/MWh. Solar PV is assumed to be curtailed at –20€/MWh. By 2030, across all scenarios, solar generation in Finland is not curtailed, as electricity prices remain above or at –5 €/MWh. Onshore wind curtailment reaches 853 GWh in the Base case, 1,428 GWh in Scenario 2, 1,091 GWh in Scenario 3, and 2,039 GWh in Scenario 4 (Fig. 12).

The model is set to curtail wind before solar, reflecting the current European market behaviour. Large wind turbines can easily reduce output by adjusting blade angles, while many solar producers lack the capability or incentives to do so. Residential solar producers, for instance, often have fixed-price contracts, transmission fees and taxes that maintain power value despite negative market prices. Additionally, solar panels degrade under sunlight, encouraging continuous operation even during low demand.

Discussion

The goal of this study was to evaluate the economic feasibility of installing extreme amounts of solar PV without economic subsidies. As many prominent organisations estimate, the current extensive expansion of solar PV installation at utility scale is likely to continue in the Nordic and Baltic region, raising concerns about the economic viability on market basis.

The scenario analysis highlights the potential economic challenges by 2030 due to additional solar PV in Finland. The results indicate that with increasing solar capacity, electricity prices decline, midday prices drop further, and evening price peaks become more pronounced, indicating economic concerns. In Scenario 4, by 2030, CR falls to 40% and UR to 17 €/MWh, compared to 76% and 41 €/MWh, respectively, in the Base case. These declining CR and UR values with high solar penetration highlight the diminishing ability to capture market value due to the oversupply during peak generation hours. The impact of neighbouring

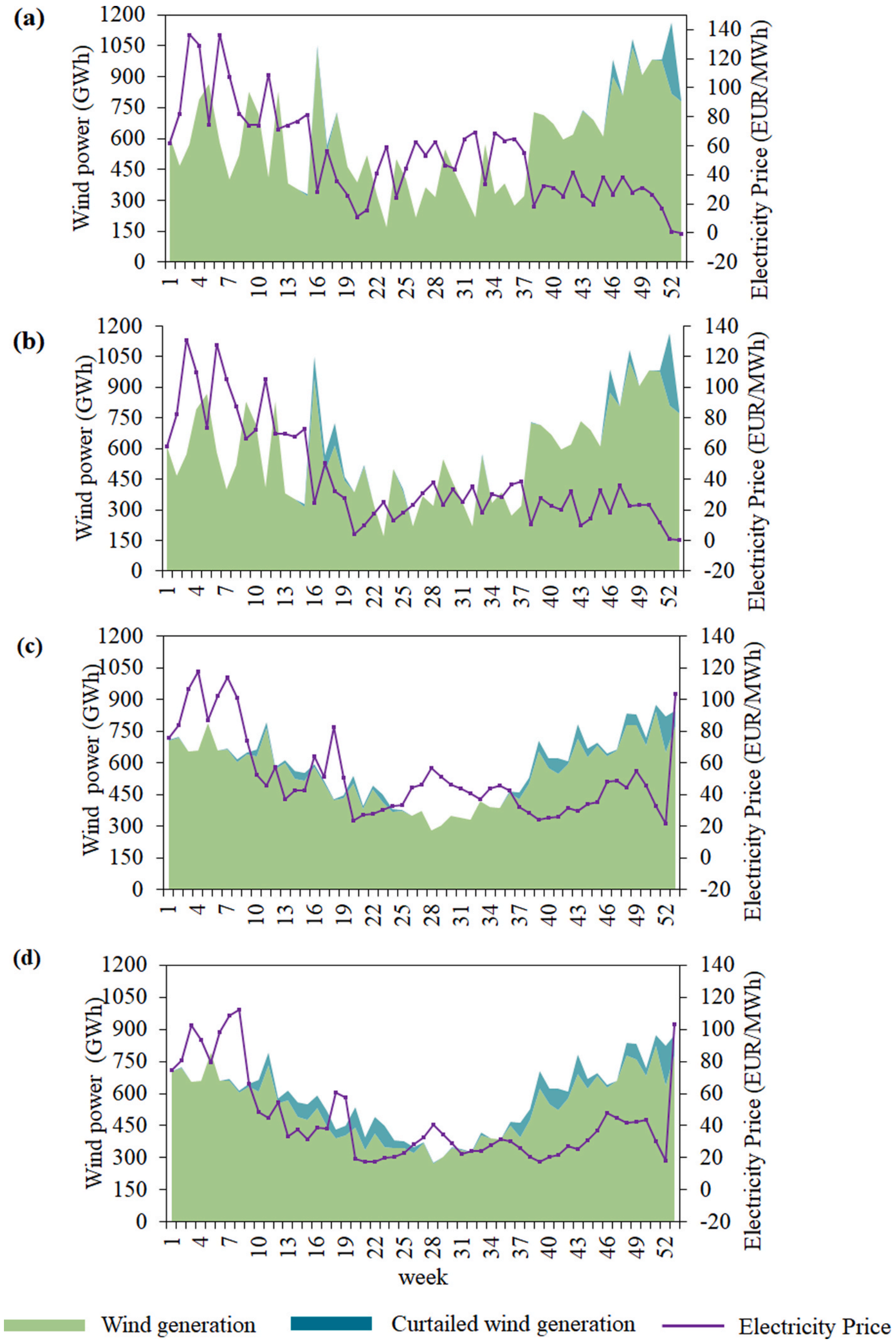

Fig. 12. Wind curtailment in 2030 (Weather year 2013) (a) Base case, (b) Scenario 2, (c) Scenario 3 and (d) Scenario 4.

regions on the Finnish energy system is found to be considerable. Expanding solar capacity in Finland alone (Scenario 2) has a greater impact on solar CR than expanding capacity only in the southernmost bidding zones of the Nordics (Scenario 3). However, expanding solar capacity in both Finland and the Southern Nordics together (Scenario 4) has a significantly stronger effect on CR than expansion in Finland alone.

As one possibility for improving the economics of PVs, VBPV integration was analysed. The integration of VBPV in the largest solar capacity expansions (Scenario 4) was found to provide significantly larger revenues for PV. The results depict that VBPV would improve production by 7-8% and total annual revenues by 8-19%, respectively, with VBPV shares of 10%-40% in Finland. Since the VBPV profiles used in this study are based on data from southern Finland, the generation could be further enhanced with average Finnish VBPV profiles as the generation tends to increase at higher latitudes. This means that the average Finnish VBPV profile could offer slightly better production and revenues than assumed in this study.

The largest single change on the consumption side in the next years will be the rapid increase of EVs, and they were modelled with optimisation of charging costs, thus supporting the economics of PV. The flexibility in demand significantly contributes to the electricity price and, consequently, the solar CR of Finland. However, in reality, the flexibility of the energy system may differ from the assumptions in this model. At the moment, many EV owners do not yet adjust their charging patterns based on electricity spot prices [63].

While this study focuses on Finland, the results underscore the need to assess the economic viability of solar PV expansion in other Nordic regions as well. Future research should consider evolving market dynamics, increased indirect cannibalisation, and the role of emerging technologies in supporting large-scale solar PV integration.

Conclusions

The rapid expansion of utility-scale solar in the Nordic region is expected to continue, raising concerns about market-based economic viability. This study shows that under the current solar PV outlook, integrating several gigawatts more PV in Finland requires optimised EV charging and district heating electrification. An even higher deployment, modelled in this study as 12 GW in Finland, alongside increased solar capacity in the southern Nordics, could significantly lower the Finnish electricity prices and reduce the solar capture rate to 40% by 2030. To adapt to the power market, integrating vertical bifacial PV and optimising flexible demand, including EV charging, are crucial. The need for curtailment of variable renewable electricity would also grow to 1-2 TWh annually. Our analysis highlights the economic challenges of large-scale solar integration, underscoring the need for timely market adjustments to sustain solar investments and support the energy transition.

CRediT authorship contribution statement

Dilshika Heenatigala Kankanamge: Writing – original draft, Visualization, Validation, Investigation, Formal analysis, Data curation, Conceptualization. **Jaakko Jääskeläinen:** Writing – review & editing, Validation, Supervision, Methodology, Formal analysis, Conceptualization. **Sami Jouttijärvi:** Writing – review & editing, Data curation, Conceptualization. **Sanna Syri:** Writing – review & editing, Project administration, Funding acquisition, Conceptualization.

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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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Modelling in this research article was performed using PLEXOS software, pursuant to a Research End User License Agreement provided by Energy Exemplar.

Author contribution statement

Dilshika Heenatigala Kankanamge is the main author of this paper. All authors participated in designing the study. Dilshika Heenatigala Kankanamge has collected the input data for the study, Jaakko Jääskeläinen has supervised the data acquisition, model setup and the use of PLEXOS model. Jaakko Jääskeläinen and Sanna Syri have participated in writing the paper have reviewed the results and participated in formulating the discussion and conclusions. Sami Jouttijärvi has modelled VBPV profiles and participated in writing and reviewing the paper. Sanna Syri was responsible for project administration and funding acquisition. This is an academic contribution and does not reflect the views of any organisation.

Appendix

Table A1
Annual average electricity price in all modelled regions in the analysed scenarios 1-4 in 2030, calculated based on the mean electricity price of ten weather years from 2007-2016.

Bidding Zone	Average Annual Electricity Price (€/MWh)			
	Base case	Scenario 2	Scenario 3	Scenario 4
DK1	58.80	58.56	51.13	50.92
DK2	58.05	57.65	50.81	50.41
EE	68.07	66.47	67.45	65.72
FI	53.98	46.8	50.41	42.36
LT	65.26	64.32	64.67	63.66
LV	68.07	66.47	67.45	65.72
NO1	55.89	55.16	52.02	51.5
NO2	55.99	55.49	52.64	52.27
NO3	38.45	36.27	33.72	32.4
NO4	37.14	34.7	31.71	30.13
NO5	55.90	55.16	52.03	51.51
SE1	33.20	30.48	26.94	24.94
SE2	32.95	30.4	26.19	24.52
SE3	41.69	39.28	35.26	33.54
SE4	42.17	39.86	35.82	34.18

Data availability

The data supporting the findings of this study are available at Zenodo via DOI : https://doi.org/10.5281/zenodo.14905616

The repository contains hourly electricity price data in the scenarios analysed in this article. The included data sets are:

Scenarios 1–4 hourly Finnish electricity prices (€/MWh) and solar PV generation (MW) across ten weather samples (2007–2016).

Scenarios 1–4 Mean hourly Finnish electricity prices (€/MWh) and solar PV generation (MW) calculated from ten weather samples (2007–2016).

Scenario 5 hourly Finnish electricity prices (€/MWh), PV, and VBPV generation (MW) for each VBPV share (10%–50%) across ten weather samples (2007–2016).

Scenario 5 Mean hourly Finnish electricity prices (€/MWh), PV, and VBPV generation (MW) for each VBPV share (10%–50%), calculated from ten weather samples (2007–2016)

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